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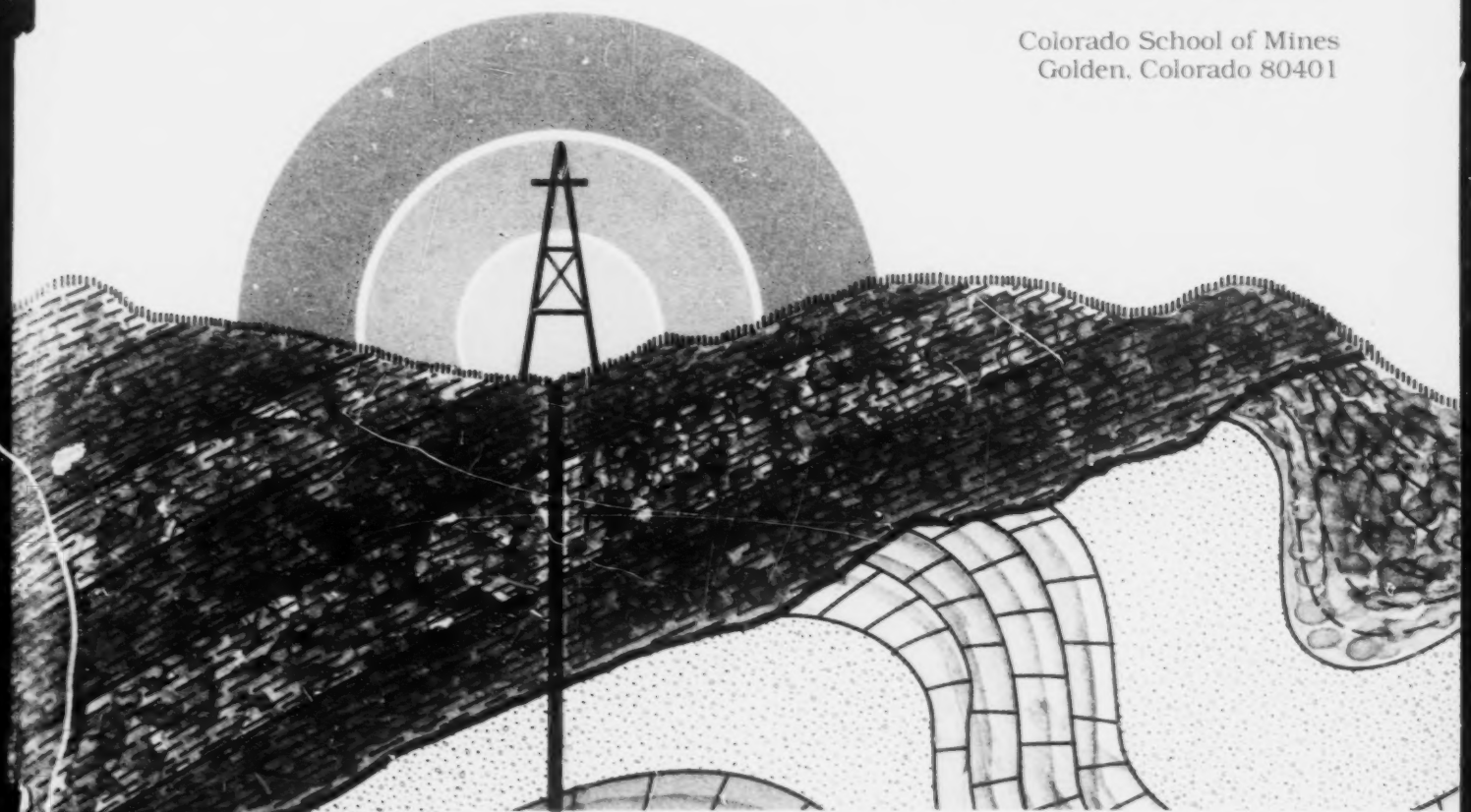
POTENTIAL SUPPLY OF NATURAL GAS IN THE UNITED STATES

(as of December 31, 1980)

Potential Gas Committee
Potential Gas Agency

Colorado School of Mines
Golden, Colorado 80401



Including Reviews of Potential Gas Resources from Nonconventional Sources and of Potential Conventional Resources of Natural Gas in Canada

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The Potential Gas Committee comprises volunteer members from the natural gas industry, government agencies, and academic institutions who are concerned with natural gas resources.

The Committee functions independently but with the guidance and assistance of the Potential Gas Agency of the Colorado School of Mines. The Potential Gas Agency is supported by the American Gas Association.

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POTENTIAL SUPPLY OF NATURAL GAS IN THE UNITED STATES

(as of December 31, 1980)

Report of the Potential Gas Committee
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Editorial Committee
Charles L. Neumeyer, Chairman
Charles J. Crowley
A. M. Derrick
E. Floyd Humphries
E. A. Rassinier
Ex officio:
George C. Grow, Jr.
Harry C. Kent

Report of the Potential Gas Agency
Harry C. Kent, Director
including a review of
Potential Gas Resources from Nonconventional Sources

James C. Donaldson
James J. Emme
Harry C. Kent

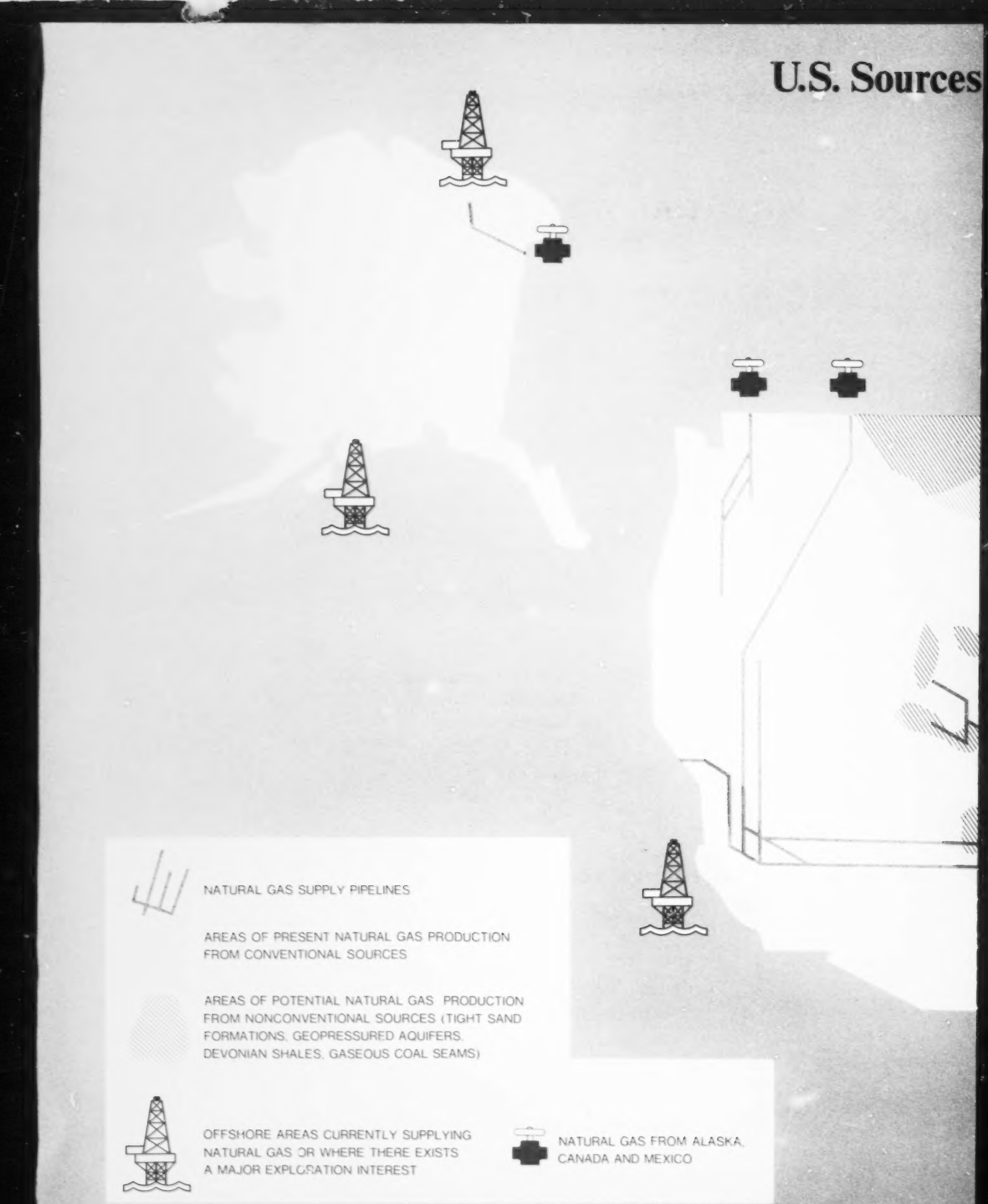
Review of Potential Conventional Resources of Natural Gas in Canada

Donald W. Axford
A. A. Wilkins
Canadian Observers to the Potential Gas Committee

Potential Gas Agency
Colorado School of Mines

May 1981

U.S. Sources



NATURAL GAS SUPPLY PIPELINES

AREAS OF PRESENT NATURAL GAS PRODUCTION FROM CONVENTIONAL SOURCES

AREAS OF POTENTIAL NATURAL GAS PRODUCTION FROM NONCONVENTIONAL SOURCES (TIGHT SAND FORMATIONS, GEOPRESSURED AQUIFERS, DEVONIAN SHALES, GASEOUS COAL SEAMS)

OFFSHORE AREAS CURRENTLY SUPPLYING NATURAL GAS OR WHERE THERE EXISTS A MAJOR EXPLORATION INTEREST

NATURAL GAS FROM ALASKA, CANADA AND MEXICO

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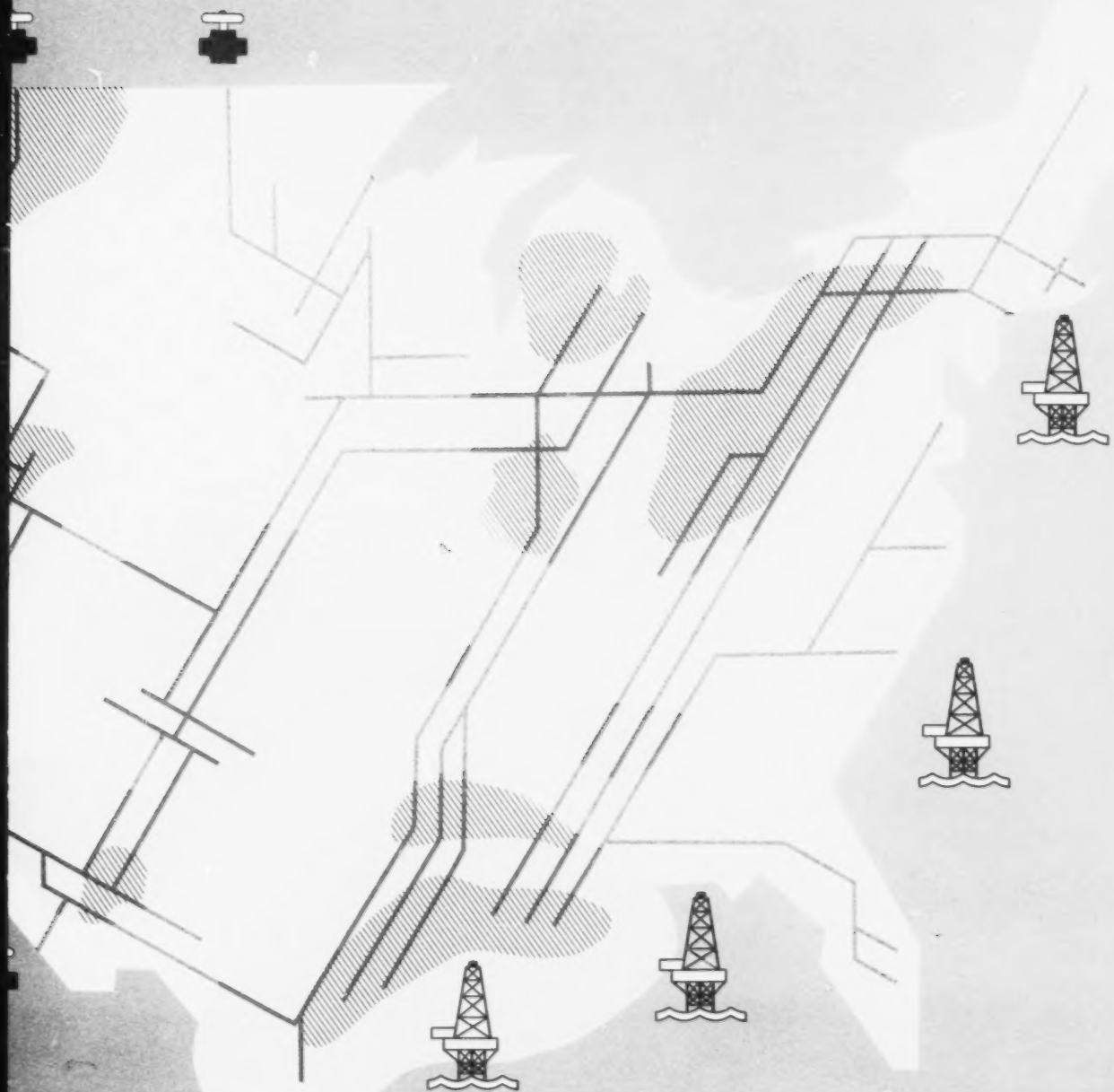
Of Conventional And Nonconventional Gas and the Natural Gas Transmission System



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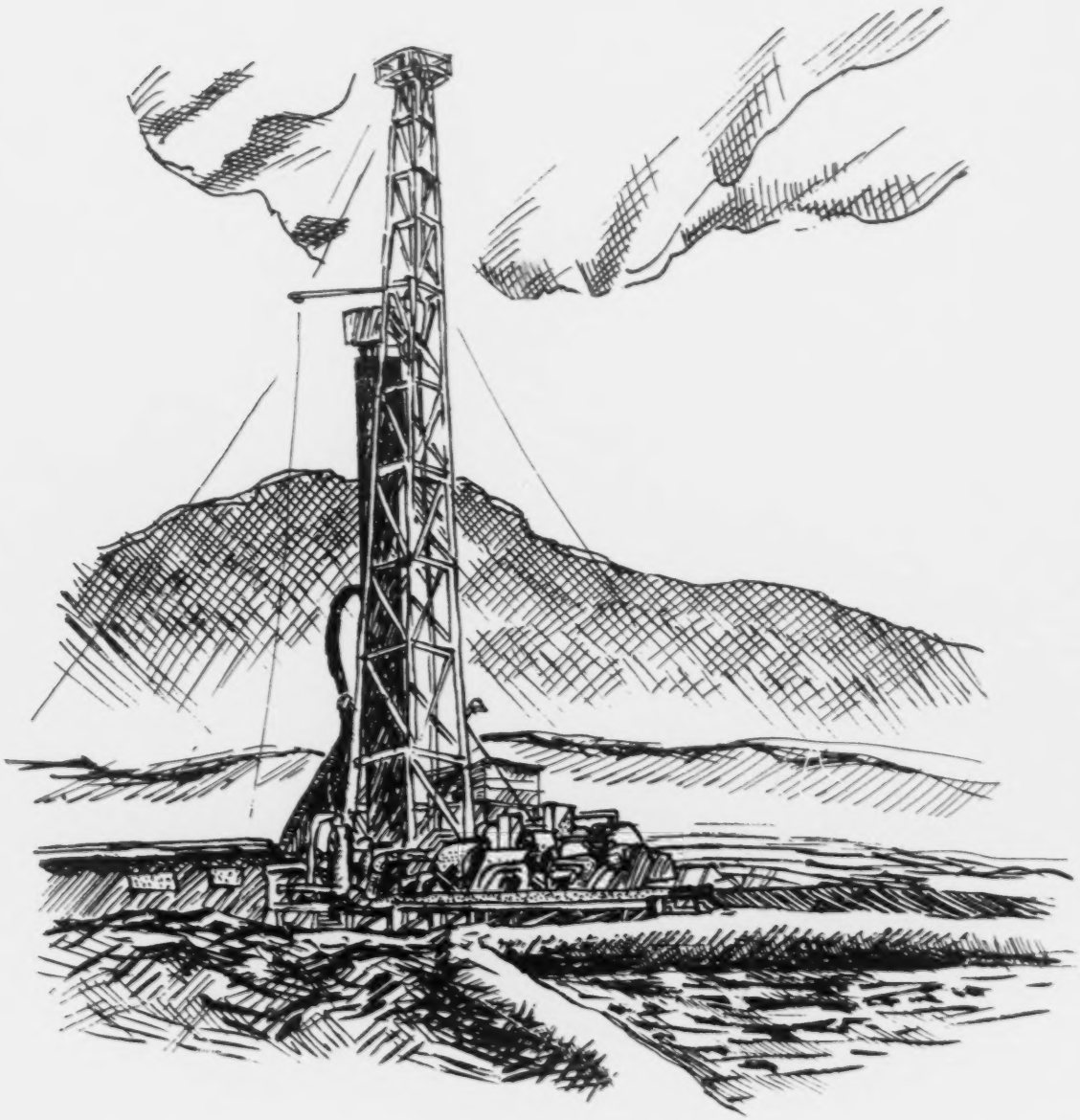
REPORT OF THE POTENTIAL GAS COMMITTEE



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REPORT OF THE POTENTIAL GAS COMMITTEE

Summary

The Potential Gas Committee comprises volunteer members from the natural gas industry, government agencies, and academic institutions who are concerned with natural gas resources. The Committee functions independently but with the guidance and assistance of the Potential Gas Agency of the Colorado School of Mines. The Potential Gas Agency is supported by the American Gas Association. Biennial estimates of the potential supply of natural gas have been prepared and published since 1966, with the exception of 1974.

The Potential Gas Committee's estimate of the potential supply of natural gas in the United States, as of December 31, 1980, is as follows:

Table 1 — Estimated potential supply of natural gas (trillions of cubic feet at 14.73 psia and 60° F.)

	Probable	Possible	Speculative
Lower 48 States			
—Onshore	151	264	196
—Offshore	34	65	58
Alaska			
—Onshore	6	16	28
—Offshore	2	13	80
Total United States	193	358	362

The sum of these estimates represents a total resource potential of 913 trillion cubic feet (Tcf).

The foregoing estimates represent the conventional potential supply expected to be recovered by future drilling under conditions of:

1. Adequate economic incentives in terms of price/cost relationships, and
2. current or foreseeable technology.

These estimates do not assume any fixed time schedule for the discovery and production of future gas supply.

The Potential Gas Committee's estimates do not include and are distinct and separate from the volume of proved recoverable natural gas reserves estimated by the Committee on Natural Gas Reserves of the American Gas Association. That Committee has estimated proved recoverable reserves in the United States to be 195 trillion cubic feet as of December 31, 1979. The relationship between proved reserves and the several categories of potential natural gas supply is illustrated in figures 2 and 3, and described in detail in the section entitled "Categories of Natural Gas Resources."

The Potential Gas Committee's previously published estimates of each category, as of December 31, 1978, of the potential supply of natural gas in the United States were as follows (trillions of cubic feet): Probable 199, Possible 399, and Speculative 421.

Comparison of these totals with the new estimates presented in table 1 reveals significant decreases between 1978 and 1980 in both the Possible and Speculative categories. The decrease in the total estimate for the Speculative category largely reflects re-evaluation of industry's former optimism toward the gas potential for the Atlantic offshore areas and Alaska. Although 1980 Speculative estimates show a large increase for Area H reflecting favorable exploration results in Wyoming, Utah and Colorado basins, this increase was offset by the decreases in Alaska and offshore Atlantic. The decrease in the total estimate for the Possible category also reflects the decrease in estimated potential for Alaska, which accounts for 27 percent of the decrease. The remaining decrease in total estimate for the Possible category is because of a number of small changes throughout the United States as potential areas were re-evaluated and as quantities were shifted from the Possible category to the Probable category. Only a slight decrease occurred overall in the Probable category. There has been a significant increase in the estimates for all categories for resources which are projected to exist in onshore areas at drilling depths of 15,000 to 30,000 feet. This increased optimism for the resource potential of deeper reservoirs is based on the larger amount of geophysical and geological information now available and on the success of recent deep exploratory drilling. Estimates for all categories reflect the net result of decreases in potential supply due to transfers from potential supply to proved reserves, re-evaluations of estimates within potential supply categories, and transfers from one potential supply category to another as new information has been obtained from exploration activities and drilling.

Introduction

The objective of the Potential Gas Committee is to provide realistic estimates of the potential supply of natural gas which, in conjunction with estimates of proved reserves of natural gas, make possible an appraisal of long-range gas supply.

Annual estimates of proved reserves of natural gas in the United States were prepared, through 1979, by the Committee on Natural Gas Reserves of the American Gas Association. These estimates are, by definition, limited to those estimated proved recoverable reserves of natural gas which have been established by drilling. Such estimates do not reflect potential supplies of natural gas which may be discovered as a result of future exploratory drilling. It is the estimates of future potential supply which are the concern of the Potential Gas Committee and which are discussed in this report.

A report on the potential resources of natural gas from nonconventional sources is included in Part II of this publication. It represents a review of the information available to the Potential Gas Agency to the time of publication. It is not an independent evaluation of the potential of these resources by either the Potential Gas Committee or the Potential Gas Agency but it is an attempt to consolidate a brief review of potential nonconventional resources of natural gas currently being investigated in this country. This report was prepared in the offices of the Potential Gas Agency by James C. Donaldson and James J. Emme, and it was reviewed by a number of experts in the respective fields who are credited at the beginning of the report.

A second report, and a new addition to the biennial reports on potential supply of natural gas in the United States, is a review of the potential resources of conventional natural gas in Canada. This review was prepared by Donald W. Axford and A. A. Wilkins, who are the Canadian observers to the Potential Gas Committee, and is included in Part III of the report. Data contained in the review are taken entirely from Geological Survey of Canada Open-File Release No. 767, prepared by R. M. Proctor, P. J. Lee and D. N. Skibo and released in March 1981.

HISTORY OF POTENTIAL GAS COMMITTEE

For many years, estimates of future supply of natural gas have been developed by numerous individuals and organizations. Since these estimates of future supply varied widely and often had entirely different objectives and meanings, they have served to confuse rather than to clarify the long-range outlook for natural gas supply. With the view to achieving a more unified industry-sponsored effort, many of the leaders of the natural gas industry, as well as various financial and governmental agencies, expressed a strong desire for a continuous long-range study of the requirements and supply of natural gas in the United States. As a result, in 1960 the Future Requirements and Supply Committees were formed and charged with the responsibility of developing such estimates. The Supply Group was organized into twelve area subcommittees that were comprised of many qualified geologists and engineers, each expert in the occurrence of natural gas in a particular area. Each area subcommittee chairman was responsible for the estimate of potential supply of natural gas in a geologically significant area of the United States. Participation by producers, distributors, pipeliners, state organizations, academicians, and consultants assured the objectivity of the study. The Future Gas Supply Committee issued its report in 1964 giving the committee's estimates of the United States potential gas supply as of the end of 1963.

In June 1966, the Gas Industry Committee, composed of representatives of the American Gas Association, the American Petroleum Institute and the Independent Natural Gas Association of America, suggested supporting a study of the future natural gas supply. In October 1966, an organizational structure was set up which provided for even broader and more diversified representation from other organizations interested in gas supply. Active supervision by the Mineral Resources Institute of the Colorado School of Mines Foundation, Inc., also was provided by the new structure. Formal announcement of the reorganized structure of the several committees was made in February 1967.

The initial report of the Potential Gas Committee was published in 1967 and covered the estimated potential gas supply as of December 31, 1966. Subsequent reports presented the Committee's estimates as of the ends of the years 1968, 1970, 1972, 1976, and 1978.

After the publication, in November 1973, of the report as of 12 31 72, a study was undertaken to determine if the work of the Potential Gas Committee should be continued and if the Committee should continue to publish regular reports. Early in 1976 it was determined that the program should continue and the decision was made to prepare estimates of the potential gas supply as of the end of 1976. Sponsorship of the Potential Gas Agency and, through it, the Potential Gas Committee was transferred from the Gas Industry Committee to the Gas Supply Committee of the American Gas Association.

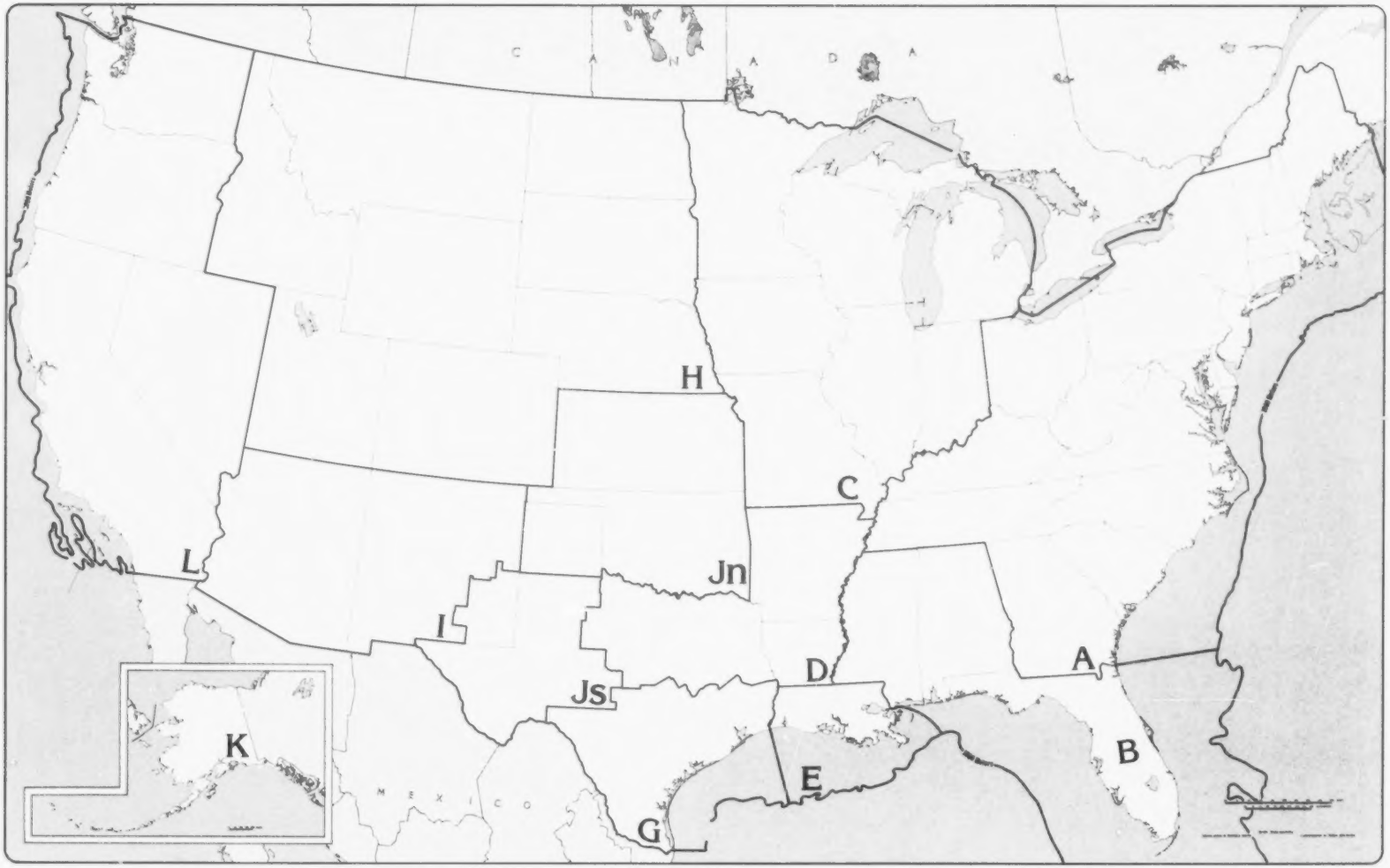


Figure 1 — Reporting areas—Potential Gas Committee

ORGANIZATION

The structure of the study of the potential supply of natural gas is divided into three parts consisting of the Gas Supply Committee of the American Gas Association, the Potential Gas Agency, and the Potential Gas Committee. The organization is shown graphically in figure 48 (Part IV).

The Gas Supply Committee of the American Gas Association takes no part in the work or the deliberations of the Potential Gas Committee or its subcommittees. Its functions are: to establish policy and objectives, to provide financial support, to select the Potential Gas Agency, and to aid in obtaining qualified manpower for the Potential Gas Committee and its subcommittees. The Gas Supply Committee does not participate in the studies leading to the estimates of potential supply of natural gas and it neither approves nor disapproves the definitions and procedures, the estimates, or the report.

The Potential Gas Agency functions under the direction of the Vice President for Academic Affairs of the Colorado School of Mines. The School, with the approval of the Gas Supply Committee, appoints staff personnel to the Potential Gas Agency. The Agency is charged with the maintenance of scientific standards and objectivity of studies, and publishes the reports of the Potential Gas Committee. The Agency appoints the Chairman and Regional Vice Chairmen of the Potential Gas Committee, approves the appointment of members, representatives, and observers to the Potential Gas Committee, and the chairmen of all subcommittees.

The Potential Gas Committee comprises members, representatives, and observers from the producing, pipeline and distribution branches of the gas industry, together with observers from the American Gas Association, the Department of Energy, the Federal Energy Regulatory Commission, the U.S. Geological Survey, the National Association of Regulatory Utility Commissioners, the Interstate Oil Compact Commission, the Bureau of Mines, the Gas Research Institute, and the Institute of Gas Technology, and representatives from Canada.

Twelve Area Work Committees are the backbone of the Potential Gas Committee. Each of the Work Committees has the responsibility of developing an estimate of the potential supply of natural gas in a particular part of the United States. Following the system long used by the petroleum industry, each Area Work Committee is assigned geologically significant areas (without specific regard to state lines) in which the Committee members have expert working knowledge. Figure 1 shows the boundaries of the Area Work Committee assignments. These committee members, with their fund of information (often confidential), are the source of knowledge and judgment for estimating the undiscovered gas supply in each area. Because geologic rather than geographic divisions are used, publication of estimates by individual states is not feasible.

The membership of Area Work Committees consists of employees and consultants associated with the producing, pipeline, and distribution segments of the gas industry — as well as qualified personnel from State and Federal Agencies and educational institutions. The guidelines specify that each Area Work Committee is to have at least one officially designated representative from both the natural-gas pipeline and distribution segments of the industry.

For administrative purposes, the Area Work Committees are grouped together in three regions: Eastern, Central and Western. Each of these regions is supervised by a Regional Vice Chairman who coordinates activities of the Area Work Committees within his jurisdiction and works with the Potential Gas Committee Chairman in order to assure that there is an open flow of communication in both directions, and that the established techniques for resource estimation are being followed by the Area Work Committees.

The Chairman of the Potential Gas Committee is assisted by the three Regional Vice Chairmen and by an Executive Committee composed of senior members of the Potential Gas Committee, including past chairmen. It is the function of the Executive Committee to advise the Chairman on policy matters. An Editorial Committee is charged with approving the content of the report of the Potential Gas Committee.

The Definitions and Procedures Committee has the responsibility of reviewing and recommending to the membership of the Potential Gas Committee any proposed changes in the definitions and procedures used in the estimation of potential gas resources.

The membership of the Potential Gas Committee, the Area Work Committees, the Executive and Editorial Committees, and other subcommittees is given in Part IV of this report. Brief biographical information for members is also included.

Categories of Natural Gas Resources

The estimates of potential supply of natural gas presented in this report can be used responsibly only with a thorough understanding of how they are defined and what they represent. An overlying constraint on estimating the amount of any natural resource is what

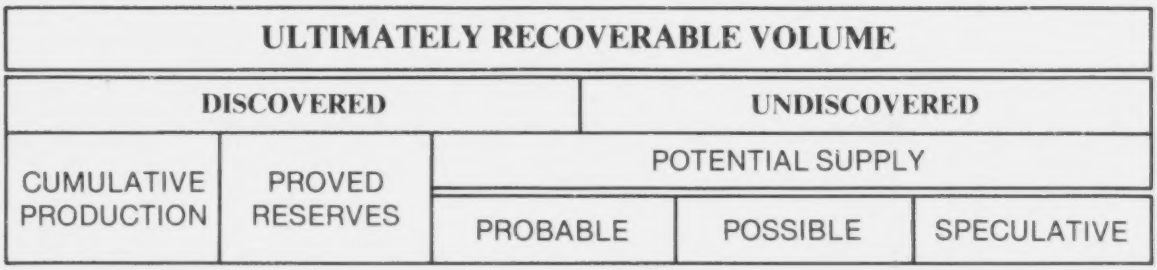


Figure 2 — Categories of past, present and future natural gas supplies

is known about it. Unlike some other resources, natural gas is unseen and very diffuse. It is found in porous rocks buried beneath the surface of the earth. Accumulations are found in a wide variety of structural and stratigraphic traps. Such characteristics make precise estimates difficult to calculate without a large amount of data. Since the data base is never as complete as one may wish, estimates are often considered to be inaccurate and, therefore, subject to severe criticism.

In order to be able to report reliable and meaningful estimates, the Potential Gas Committee has adopted a number of supply or resource categories. To ensure credibility, the categories are established on the basis of specific criteria. Much of what is known about natural gas accumulation is based on geological principles. It is, therefore, reasonable to utilize this type of knowledge and the availability of this knowledge as a basis for defining specific categories. The categories of natural gas resources used by the Potential Gas Committee are shown in figure 2 and are defined and discussed in the following section. A schematic representation of the various categories of potential supply is illustrated in figure 3.

DEFINITION OF NATURAL GAS

Natural gas, as used in this report, is any gas of natural origin that is composed primarily of hydrocarbon molecules producible from a borehole. Most natural gas contains some nonhydrocarbon components such as carbon dioxide, nitrogen, hydrogen sulfide, helium, etc.; however, in estimating potential supply, it is not feasible to separate small volumes of these components from the hydrocarbons. In areas or formations that are believed to contain large volumes of such nonhydrocarbons, these components are not counted as potential supply.

NATURAL GAS RESOURCES

At a given time a finite volume of natural gas in-place exists within the rocks of the shallow portion of the earth's crust. This finite volume of gas in-place is the natural gas resource. The amount of this resource which is recoverable now or in the future is a function of technology and economics. Today, technology has advanced to the degree that a large part of the resource base can be recovered. A part of this resource, however, is not recoverable because it is dispersed throughout the rock in minute accumulations which cannot be extracted with existing or foreseeable technology, and also because the cost of recovery of this gas is too high compared to the value of the gas. Even if the technology were to exist, production of some deposits would not be feasible because recovery of such accumulations would require more energy than that provided by the gas produced.

Estimates of the Potential Gas Committee include only the natural gas resource which can be discovered and produced using current or foreseeable technology and under the condition that the price/cost ratio will be favorable. This total quantity is referred to as the *Ultimately Recoverable Volume*. In previous reports of the Potential Gas Committee, this quantity has been referred to as *Ultimately Discoverable Volume*. Both terms are synonymous, but the new terminology has been adopted in this report to emphasize that the Committee is presenting estimates of natural gas which they believe can be both *discovered* and *recovered* under the limiting conditions established by the Committee.

The *Ultimately Recoverable Volume* represents the quantity of natural gas expected to be produced during the life of the industry through exploration and development of the resource. Recovery would be effected by utilizing conventional techniques of exploration, drilling, completion and production and also by incorporating new technological develop-

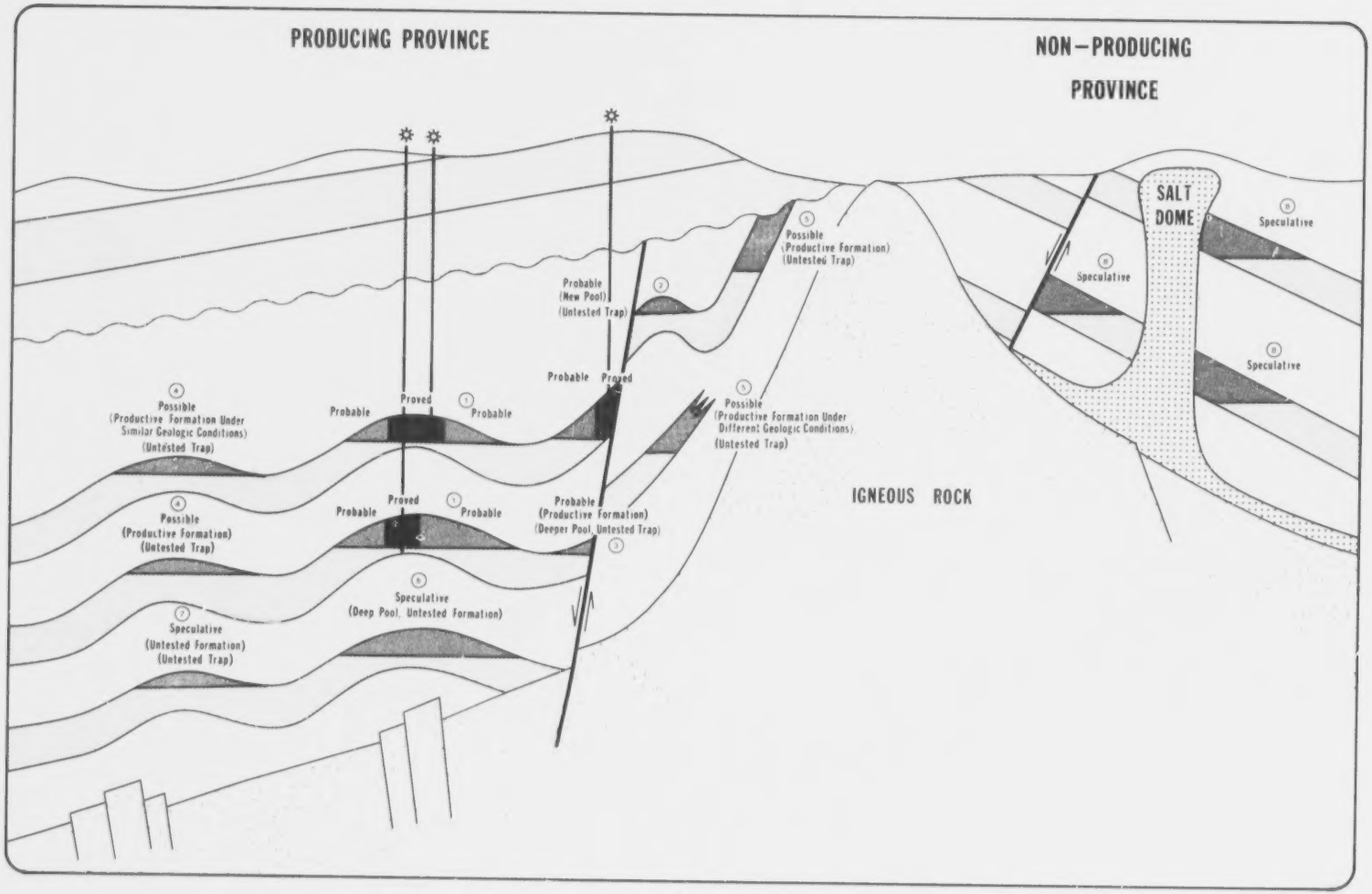


Figure 3 — Schematic representation of categories of potential supply

ments. The Ultimately Recoverable Volume is composed of both the *discovered* and the *undiscovered* natural gas resources. Discovered gas consists of the quantity which has been produced in past years plus that which has been proved by drilling and engineering tests and is included in present *Proved Reserves*. Additionally, discovered gas includes the gas, remaining in known fields, which will be recovered through extension and complete development of known pools and reservoirs. The undiscovered resource consists of the potential gas supply which is expected to become productive upon further exploration and development and includes both the gas remaining in undiscovered pools and reservoirs within known fields and the gas which may be discovered in new fields and reservoirs within provinces which are presently productive and within provinces which are as yet unproductive.

The subdivision of Ultimately Recoverable Volume into categories reflects the variation in the amount of geological and engineering information upon which the estimate is based. Proceeding from left to right in figure 2, the level of geological and engineering knowledge decreases.

Past production is reported as cumulative production and is the total volume of natural gas withdrawn from producing reservoirs. Some uncertainty involving the amount of production from earlier years exists as a result of incomplete records, but a reasonable estimate has been made based on available information. Estimates of past production presented in this report have been prepared by the Committee on Natural Gas Reserves of the American Gas Association.

Proved reserves are the currently estimated quantity of natural gas which analysis of geologic and engineering data demonstrate with reasonable certainty to be recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions. Reservoirs are considered proved that have demonstrated the ability to produce by either actual production or conclusive formation tests. The Potential Gas Committee does not estimate volumes of proved reserves. Estimates of proved reserves were compiled annually from 1946 through 1979 by the Committee on Natural Gas Reserves of the American Gas Association (AGA). The AGA estimates have been largely supplanted by reports prepared by the Energy Information Agency of the U.S. Department of Energy (EIA). EIA reports of U.S. proved reserves began with data for 1977 and are expected to replace the AGA estimates for 1980 and subsequent years.

The *Potential* supply includes the remaining portion of discovered gas resource in addition to proved reserves and all of the undiscovered resource. Three categories of potential supply are recognized and reported by the Potential Gas Committee: Probable, Possible and Speculative. These three categories are differentiated on the basis of variation in available geologic information. The reported figures are the estimate of the most likely amount of natural gas (i.e., modal value) that can be expected to be found and recovered in each category.

Probable potential gas supply is associated with existing fields. It is the most assured of potential supplies because it is associated with known accumulations and a relatively large amount of geological and engineering information is available to aid in estimation of the reported figures in this category. The Probable supply bridges the boundary between discovered and undiscovered resources. The discovered portion includes supply from future extensions of *existing pools* in known productive reservoirs [1].* The undiscovered portion of Probable supply is expected to come from future *new pool* discoveries within existing fields either in 1) reservoirs productive elsewhere in the field [2], or 2) in shallower or deeper formations known to be productive elsewhere in the same geologic province or subprovince [3].

Possible potential supply is a less assured supply because it is postulated to exist outside of known fields,

Figure 3 — Schematic representation of categories of potential supply

I Probable — Associated with existing fields — most assured,
  1) Discovered: discovered trap, existing production [1]
  2) Undiscovered: undiscovered trap, productive formation — supply from new pool discoveries within existing fields in
    a) reservoir producing within the same field [2]
    b) shallower or deeper formations producing elsewhere within same geologic province or subprovince [3]

II Possible — Associated with productive formations — less assured,
  1) Similar geologic conditions [4]
  2) Different geologic conditions: e.g., stratigraphic vs. structural trap [5]

III Speculative — Most nebulous
  1) From nonproductive formations in productive province
    a) new pool [6]
    b) new field [7]
  2) From nonproductive province [8]

*Numbers in brackets refer to accumulations shown diagrammatically in figure 3.

UNITED STATES GEOLOGICAL SURVEY RESOURCE APPRAISAL GROUP CIRCULAR 725	INFERRED RESERVES	UNDISCOVERED RECOVERABLE RESOURCES	
POTENTIAL GAS COMMITTEE	PROBABLE	POSSIBLE	SPECULATIVE

Figure 4 — Comparison of U.S. Geological Survey and Potential Gas Committee natural gas resource classification categories

but it is associated with a productive formation in a productive province. Its occurrence is indicated by projection of plays or trends of a producing formation into a less-well-explored area of the same geologic province or subprovince. Supply is from *new field* discoveries, postulated to occur within these trends or plays under both similar [4] and different [5] geologic conditions (i.e., the types of traps and/or structural settings may either be the same or differ in some aspect).

Speculative potential gas supply is the most nebulous of new supplies. This supply is from formations or provinces which have not yet proven to be productive. Geologic analogs are developed in order to ensure reasonable evaluation of these unknown quantities. Supply is from *new pool* [6] or *new field* [7] discoveries in *formations not previously productive* within a productive geologic province or subprovince and also *new field* discoveries within a geologic *province not previously productive* [8].

To reiterate, the accuracy of the estimates of gas volumes included in the potential supply is dependent upon geological conditions and knowledge and the extent to which the given area has been explored and developed. By following the estimation guidelines as closely as possible, consistency and compatibility of the estimates by members of the Potential Gas Committee are maintained. However, the individual estimator may have to use slight modifications of the considerations and procedures when compiling estimates for each of the three categories because of the particular characteristics applicable to his reporting area.

Estimates of potential resources of natural gas in the United States are also made by the Resource Appraisal Group of the United States Geological Survey. Their most recent published report is contained in U.S.G.S. Circular 725[1] and includes estimates of crude oil and natural gas liquids as well as natural gas. A preliminary report containing revisions of the estimates in Circular 725 was issued in early 1981 as Open-File Report 81-192. Although resource terminology of the U.S.G.S. Resource Appraisal Group differs from that used by the Potential Gas Committee, the U.S.G.S. category Inferred Reserves is essentially equivalent to Probable resources, and the U.S.G.S. category Undiscovered Recoverable Resources is essentially equivalent to the combined Possible and Speculative categories (fig. 4). A further discussion of the definitions and usage of U.S.G.S. terminology is set forth in U.S.G.S. Circular 831[2].

[1] Miller, B. M., et al., 1975, Geological Estimates of Undiscovered Recoverable Oil and Gas Resources in the United States: U.S. Geological Survey Circ. 725, 78 p.

[2] U.S. Bureau of Mines and the U.S. Geological Survey, 1980, Principles of a Resource/Reserve Classification for Minerals: U.S. Geological Survey Cir. 831, 5 p.

Estimation of Potential Gas Supply

TECHNIQUES FOR ESTIMATION OF POTENTIAL GAS SUPPLY

A basic technique for estimating potential gas supply is applied to each of the categories adopted by the Potential Gas Committee. In each case, what is known about the prospective area is evaluated relative to what is known about natural gas accumulations and the factors known to control their occurrence. Studies of producing areas have provided information on the productive capacity of particular formations and the average size of accumulations. Natural gas occurrences are related to conditions which favor their formation and accumulation, such as the existence of source rocks, sufficient maturation of organic material, and presence of reservoir rocks and traps. Modification of the basic technique is necessary to accommodate the variations in amount of information available for prospective areas. In the most simplified form, the potential supply is derived by: (1) estimating the volume of potential gas-bearing reservoir rock, (2) multiplying this quantity by a yield factor,* and (3) discounting to allow for the probability that the traps and/or the accumulations exist. Figures 5-8 illustrate the modifications applied to this procedure for the different categories.

Probable potential supplies bridge the division between discovered and undiscovered resources. The discovered portion includes extensions of accumulations which are estimated to be partially developed. The undiscovered portion is composed of new pools which may be discovered within an existing field. In the case of *discovered Probable* potential (fig. 5), the volume of potential rock is calculated to the limits of pool development based on geological, geophysical and engineering data and is adjusted for such possible variations as changes in lithology, thickness, porosity, permeability, hydrodynamic conditions or gas/oil/water relationships in the reservoir. The adjusted volume is multiplied by a yield factor obtained from the area of the field which is presently producing from the same formation as the extension being evaluated.

*Yield factors represent the amount of gas expected to be produced from a given unit of rock. They are calculated using data from known gas accumulations considered to be most similar to the one being evaluated. The yield is the volume of discovered gas (i.e., cumulative production plus proved reserves) divided by the volume of productive rock.

To arrive at a *Probable* potential resource estimate, the product of the reservoir volume and the yield factor is then multiplied by the probability that the accumulation actually exists. This probability is determined by the estimator based on previous experience in development of similar fields in the province.

Estimating *undiscovered Probable* potential supply (fig. 6) involves more geological and geophysical interpretation in order to delineate all possible new pools within existing fields. The volume of potential gas-bearing reservoir rock is calculated for known and untested traps (as in the case of suspected multizone development of an anticlinal trap) and potential but unknown traps (pools separated from current production by faults or facies changes, such as overlapping barrier bars). This calculated volume is then adjusted for possible changes in lithology and reservoir characteristics. Variations of this type might include lateral changes in the bedding such as sand pinchouts or facies changes. Proper evaluation requires a familiarity with both the nature of the formation within the province and also the local facies and structural setting. The adjusted volume is multiplied by an adjusted yield factor which is obtained by analogy with a producing area similar to the potential new pool under consideration. The yield factor is adjusted to account for any differences thought to exist between the analog and the potential reservoir. These differences may include such factors as different porosities and permeabilities due to diagenetic changes resulting from different depths of burial or deposition within different energy regimes. Presence or absence of source rocks and their maturation levels must also be considered. The amount of potential supply thus calculated must then be discounted by two factors. The first discount factor is a measure of how certain the estimator is of the existence of the traps. In the case of potential multizone anticlines, the traps are known to exist and the probability is one. This probability for unknown traps is more difficult to assess and a thorough understanding of the geology is important in order to make an educated evaluation. The second discount necessarily considers the possibility that even though all conditions are favorable for an accumulation,

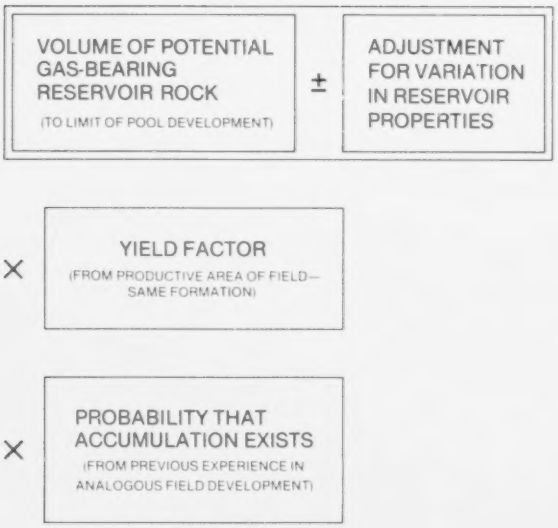


Figure 5 — Schematic procedures for estimation of discovered Probable potential supply

including the existence of a trap, no gas may actually have accumulated in the trap, for instance, because the trap did not exist at the time of migration of the gas. With inclusion of these two discount factors, an estimate of the *undiscovered Probable* potential resource can be made.

Estimating *Possible* potential supply (fig. 7) is essentially the same as for the undiscovered Probable category. Both situations involve untested traps within formations productive within the province but differ in their association with proved production. Possible supplies are located within a productive province, but away from presently productive fields. For this reason it is necessary to consider the possible existence of producing trends or plays. By extending a trend or a play from a productive area into a relatively unexplored area, a reasonable geologic interpretation can be made about the number and types of traps to be found in that region. Available geophysical or geological data may also indicate the location and possible size of potential traps. Careful evaluation of the trend or play (e.g., do the variations in reservoir or trap characteristics diminish or increase the probability of accumulation in less-well-explored areas) is necessary to ensure proper reservoir volume and yield adjustments and reasonable estimates for trap and accumulation discounts. The probabilities for the existence of traps and accumulations are dependent on how strongly the trend or play is established and the quality and quantity of available exploration data.

The estimation of *Speculative* potential supply (fig. 8) involves estimating accumulations which may be found in untested sediments located in either producing or non-producing provinces. Estimates are based on whether or not factors considered favorable for gas accumulations are present. These factors include the type of sediments to be found, their stratigraphic relationship, and tectonic and burial (thermal maturation) history. Types of sediments must be evaluated to determine if favorable reservoir and source rocks exist. Structural and stratigraphic information is necessary to decide if potential traps are present in the area. Burial history must be considered, if source rocks are present, in order to investigate possible maturation levels and if gas generation has taken place. Yield factors are estimated using known production statistics from other provinces. In these other provinces gas is produced from formations which are different from

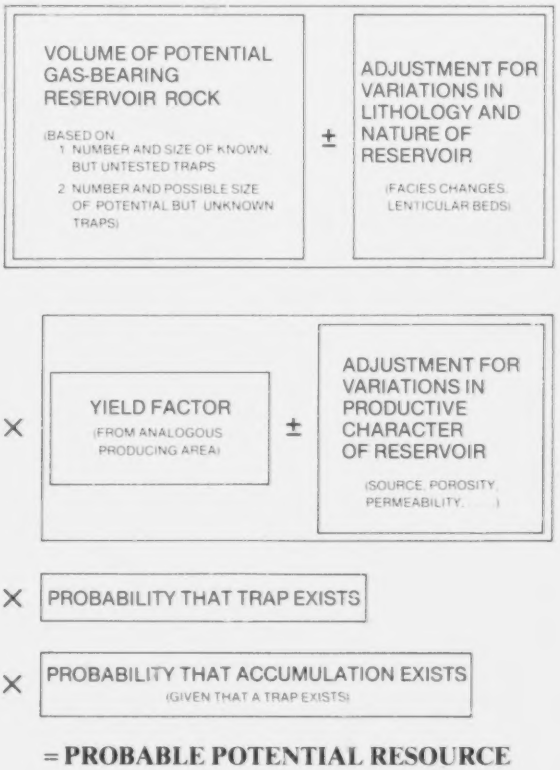

VOLUME OF POTENTIAL GAS-BEARING RESERVOIR ROCK
(BASED ON
1. NUMBER AND SIZE OF KNOWN, BUT UNTESTED TRAPS
2. NUMBER AND POSSIBLE SIZE OF POTENTIAL BUT UNKNOWN TRAPS)
±
ADJUSTMENT FOR VARIATIONS IN LITHOLOGY AND NATURE OF RESERVOIR
(FACIES CHANGES, LENTICULAR BEDS)
×
YIELD FACTOR
(FROM ANALOGOUS PRODUCING AREA)
±
ADJUSTMENT FOR VARIATIONS IN PRODUCTIVE CHARACTER OF RESERVOIR
(SOURCE, POROSITY, PERMEABILITY, ...)
×
PROBABILITY THAT TRAP EXISTS
×
PROBABILITY THAT ACCUMULATION EXISTS
(GIVEN THAT A TRAP EXISTS)
= PROBABLE POTENTIAL RESOURCE

Figure 6 — Schematic procedure for estimation of undiscovered Probable potential supply

those in the speculative province, but characteristics of the formations in both provinces are believed to be similar. Adjustments are made to allow for dissimilarities between the two provinces being compared. The probabilities that the accumulations and traps exist are generally grouped together as one discount factor in order to derive the estimate of Speculative potential resources. The experience and judgment of the estimators are critical in making estimates of Speculative potential as they are in all resource estimation.

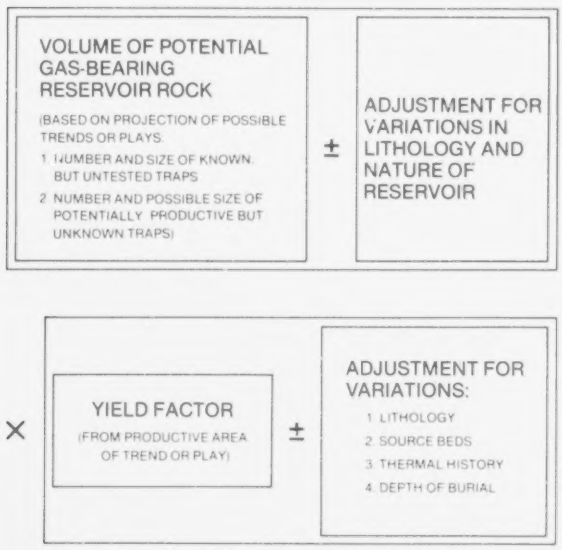

VOLUME OF POTENTIAL GAS-BEARING RESERVOIR ROCK
(BASED ON PROJECTION OF POSSIBLE TRENDS OR PLAYS:
1. NUMBER AND SIZE OF KNOWN, BUT UNTESTED TRAPS
2. NUMBER AND POSSIBLE SIZE OF POTENTIALLY PRODUCTIVE BUT UNKNOWN TRAPS)
±
ADJUSTMENT FOR VARIATIONS IN LITHOLOGY AND NATURE OF RESERVOIR
×
YIELD FACTOR
(FROM PRODUCTIVE AREA OF TREND OR PLAY)
±
ADJUSTMENT FOR VARIATIONS:
1. LITHOLOGY
2. SOURCE BEDS
3. THERMAL HISTORY
4. DEPTH OF BURIAL
×
PROBABILITY THAT TRAPS EXIST
×
PROBABILITY THAT ACCUMULATIONS EXIST
(GIVEN THAT A TRAP EXISTS)
= POSSIBLE POTENTIAL RESOURCE

Figure 7 — Schematic procedure for estimation of Possible potential supply

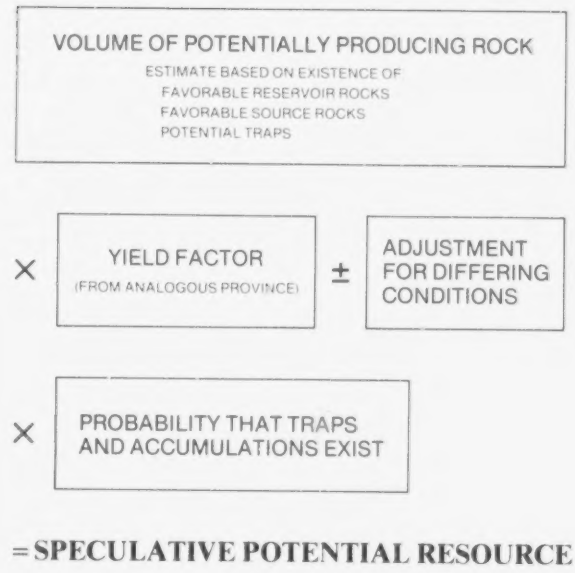


Figure 8 — Schematic procedure for estimation of Speculative potential supply

Procedures in Estimation of Potential Gas Supply

Members of the Potential Gas Committee are asked to apply the preceding techniques for estimation of potential gas supply to each geologic province, sub-province or other geologic subdivision for which they are responsible. Geologic provinces are large areas or regions which are unified in some way and which can be considered as a whole. In order to define provinces, similarity in geologic structure or stratigraphy exists throughout the province and is the defining characteristic. A geologic sub-province is a smaller area within the larger province, usually defined by close similarities in both geologic structure and stratigraphy, and in which either the same or closely similar formations exist throughout the province.

Many times natural gas accumulations are thought of as occurring in geologic basins, which are areas of thick accumulation of sedimentary rocks generally considered to have accumulated in a topographic depression on the continent formed by tectonic processes during the geologic history of the region. However, there are many areas in the United States where large quantities of natural gas have accumulated outside of recognized geologic basins. Therefore, it is not accurate to consider the basin as the fundamental area for consideration in resource estimation.

Resource estimates are made for each geologic region by members of the Committee. In many cases, especially where the potential resources are apparently quite large, two or more independent evaluations are made by individual members of the Area Work Committees. Differences between independent estimates are reconciled by discussion and re-evaluation. Each Area Work Committee, as a whole, reviews estimates of individual estimators, and, based on the

experience and knowledge of all members, accepts estimates presented or requests additional study and re-evaluation.

Each estimator is asked to consider three separate situations in preparing estimates. The first situation involves considering the quantity of gas which might exist and be recoverable under the most favorable of geologic conditions. This would mean that the maximum number of potential traps would exist with favorable source bed and reservoir conditions, and that each of the potential traps would be filled with recoverable accumulation. Such a consideration would lead to an estimate of the maximum possible resource. On the other hand, the situation is considered in which only a limited number of additional traps exist, the minimum that could be conceived based on the level of geologic information currently available, with the most marginal of source bed and reservoir conditions, and the possibility that many of the traps which might exist would not contain recoverable accumulations of natural gas. Such a consideration would lead to a minimum estimate of the resource. Finally, the estimator is asked to consider what is the most reasonable estimate both of the existence of traps and accumulations and the most reasonable assessment of the source bed and reservoir conditions. By considering all three of these situations, the estimator is best able to express both the limiting conditions within the geologic region and, also, conclude the most likely conditions to exist, having considered all factors. Only the best, or most likely, estimates are reported by the Potential Gas Committee. Neither the most optimistic outlook, resulting in a maximum estimate, nor the most pessimistic outlook, resulting in a minimum estimate, is believed to be a sound basis for future planning. The estimates which are reported are the best considered judgment of the members of the Committee based on their evaluation of all information available to them. However, it should be noted that there is a degree of uncertainty associated with each estimate which cannot be resolved until exploration, drilling, and production have been completed. The degree of uncertainty differs for each of the resource categories of the Committee. This uncertainty is discussed in more detail below. In order to present estimates for the reporting areas and depths of the Potential Gas Committee and for the United States as a whole, the best estimates for each of the geologic regions (provinces, sub-provinces, basins, etc.) are accumulated to form the totals.

Role of Judgment

The judgment of the estimator is the most significant factor in making estimates of potential supply, particularly in the resource categories of *Possible* and *Speculative*. Members of the Potential Gas Committee, having the detailed knowledge and the experience necessary to select the appropriate adjustments for an assigned geological province, use all available pertinent geological and engineering data to reflect an objective, scientific approach to the problem.

MEANING OF POTENTIAL GAS COMMITTEE ESTIMATES

The estimates presented by the Potential Gas Committee for each of the reporting areas and for each of the resource categories are the best estimates of the Committee and represent statistically the *most likely* or *modal* estimates; that is, they represent the quantity of natural gas which has the highest probability of occurrence. These most likely estimates are prepared by the members of the Potential Gas Committee following the procedures outlined in the section on Technique for Estimation of Potential Gas Supply. As explained in the preceding section, it is the policy of the Potential Gas Committee to publish only the most likely estimate for each category in each area.

The actual volume of ultimately recoverable natural gas within the crust of the earth is a fixed, but unknown, quantity. Consequently, the estimates made by the Potential Gas Committee incorporate considerable uncertainty as to whether the best estimate of the Committee corresponds to the actual quantity of recoverable natural gas present beneath the surface in a given area. The degree of uncertainty increases with decreasing availability of geological, geophysical and engineering information, and with decreasing size of area considered. Hence, the Committee's use of the categories Probable, Possible and Speculative. *In all cases, it must be emphasized that the categories Probable, Possible and Speculative relate only to the degree of certainty of the accuracy of the estimates because of the differing availability of data upon which the categories of estimates are based; the estimates presented for each category represent the Committee's judgment of the best estimate with the highest probability of occurrence.*

In actual observations of the work of the Committee, there may be a slight tendency for the best (most likely) estimates to fall closer to the minimum estimates rather than to the maximum. However, there are no statistically valid data to support this tendency. There are also many optimists within the Committee whose estimates fall closer to the maximum. Also, there is no way to relate positively the estimates to the actual resource distribution. Recognizing these potential shortcomings, members of the Committee strive to be as objective as possible in making estimates.

Estimates are released only on the basis of totals for designated areas. It is believed that estimates for individual provinces, subprovinces, basins, trends, etc. are subject to a great deal of uncertainty but that aggregated totals for larger areas incorporate both optimistic and pessimistic estimates for smaller subdivisions and, consequently, approach a realistic evaluation of the potential for the area even though the uncertainty cannot be totally eliminated.

Based on the foregoing reasons, it is believed that the Committee's estimates represent a distribution such that the most likely or modal estimates correspond closely to the statistical mean. Since estimates for an area are derived by combining estimates from subareas, it is reasonable to assume that the area estimates will follow a normal probability distribution. On this assumption, the Committee's estimates can be represented as lower, modal and upper points on a normal probability curve, and such a curve is symmetrical about the mode. The lower value corresponds to an approximately 90 percent probability that there will be at least this lower amount of recoverable gas, and the upper value corresponds to an approximately 10 percent probability that there will be this upper amount of recoverable gas.

The relationship of the most likely estimates to the probability of occurrence of natural gas resources may perhaps be best explained by reference to a hypothetical plot of the actual probability of occurrence of the given quantity of natural gas in an area (fig. 9).

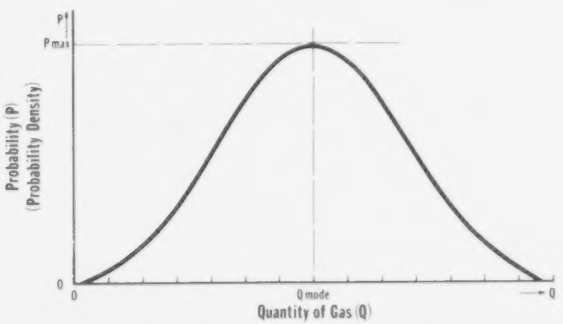


Figure 9 — Hypothetical plot of the actual probability of occurrence of the given quantity of natural gas in an area

Figure 9 demonstrates that there is the highest probability (P max) of the occurrence of a given quantity (Q mode) of natural gas at the highest, or modal, point of the curve. This Q mode is the quantity estimated by the Potential Gas Committee based on the best judgment of the members. There is a correspondingly lower probability that the actual quantity of natural gas will be something other than Q mode. Lower or higher estimates extending toward the minimum and maximum quantities which might be present can be derived by varying either the evaluation of the geologic factors which control occurrence or the discount factors applied to both the possibility of the occurrence of the trap and the accumulation of trapped gas. For example, if the reservoir conditions are not as favorable as judged by the Committee, then the quantity of gas which can be recovered would be less than that estimated by the Committee. On the other hand, if the reservoir conditions are more favorable, the quantity would be higher. Also, if the probability of both the existence of the trap and the accumulation of gas within the trap are either higher or lower, the quantity would also vary. While recognizing the possibility of this variation, members of the Potential Gas Committee feel that the most likely estimate which they present represents the best considered judgment of the Committee members as to the characteristics which exist within the area under consideration.

The "tightness" of the actual probability curve for an individual area, or the measure of uncertainty corresponding to the estimate of Q mode, will vary according to the quantity of data upon which the estimates are based and will, therefore, vary between the Probable, Possible and Speculative categories.

For Probable estimates:

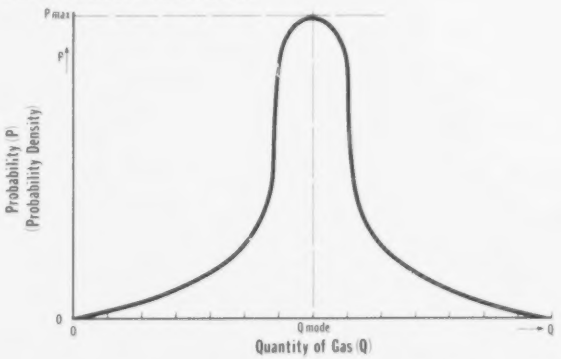


Figure 10 — Hypothetical plot of the probability of occurrence of estimates for the Probable category

It can be seen from the shapes of the curves in figures 10, 11 and 12 that there is greater uncertainty about the estimate of natural gas which is to be reported as the most likely quantity for the Speculative category than for the Probable or Possible categories. That is, there is a greater range of estimates of natural gas with a relatively high probability of occurrence and, therefore, selection of the most likely estimate for the Speculative category is more difficult than for the other categories. The uncertainty diminishes in the Possible and Probable categories with the estimate of the Probable quantity being the most certain because the greatest amount of information is available.

For Possible estimates:

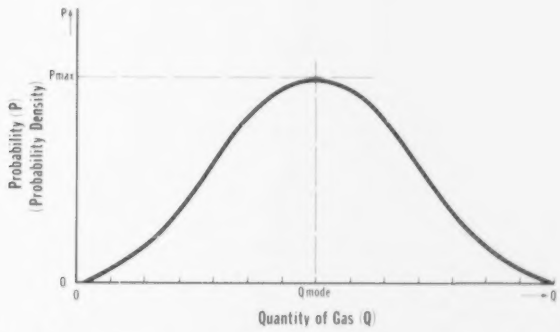


Figure 11 — Hypothetical plot of the probability of occurrence of estimates for the Possible category

For Speculative estimates:

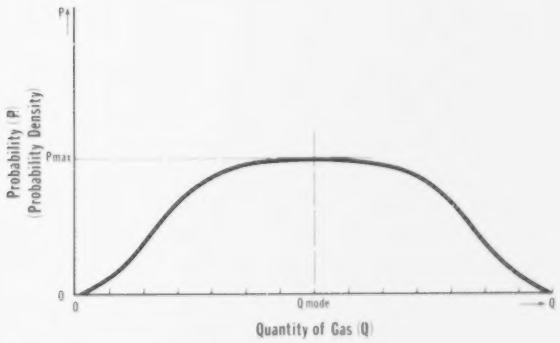


Figure 12 — Hypothetical plot of the probability of occurrence of estimates for the Speculative category

An alternate way of considering the nature of resource estimates is to look at them in terms of a cumulative probability distribution or an "at least" probability curve. In this case, the steepness of the curve will vary according to the amount of data on which it is based. For another hypothetical area, not the same as in figure 9, the cumulative probability curve is shown in figure 13.

This curve indicates that there is a very high probability of having at least a minimum quantity of natural gas present in the area and a low probability of having at least a very large amount of natural gas present. The most likely estimate or the estimate with the modal probability falls at the inflection point on the curve as indicated by the intersection of P mode and Q mode.

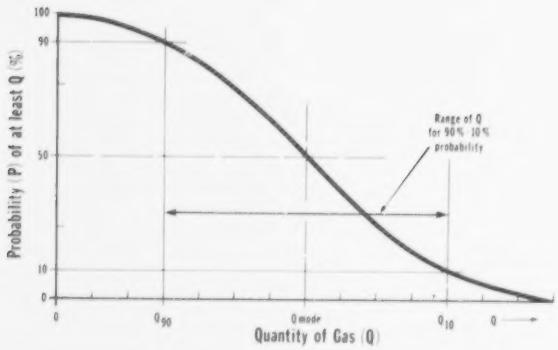


Figure 13 — Hypothetical cumulative probability (at least probability) curve for the estimates of the quantity of gas in a given area

For Probable estimates:

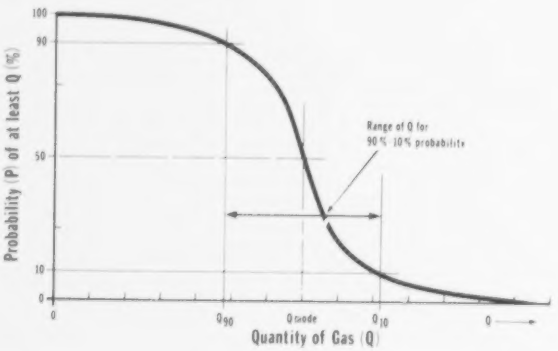


Figure 14 — Hypothetical cumulative probability (at least probability) curve for Probable estimates

For Possible estimates:

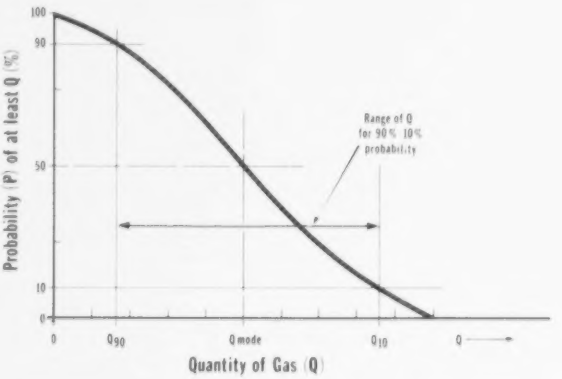


Figure 15 — Hypothetical cumulative probability (at least probability) curve for Possible estimates

For Speculative estimates:

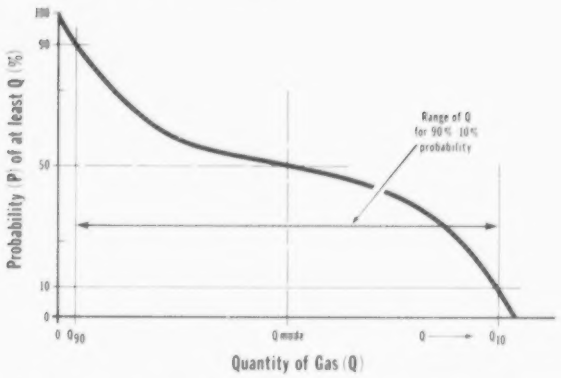


Figure 16 — Hypothetical cumulative probability (at least probability) curve for Speculative estimates

It will be noted that in the case of the Probable estimate, there is a narrow range of values of Q between the lower quantity with a high probability of occurrence (represented by Q90, or 90% probability) and the upper quantity with a low probability of occurrence (Q10, or 10% probability). The curve for possible estimates is intermediate and there is a wider range between Q90 and Q10, and the curve for speculative estimates indicates that there is a broad range between the lower (Q90) and upper (Q10) quantities.

Under the conditions related to the estimates of the Potential Gas Committee, within each category the most likely estimates for each individual basin, province or trend are additive and can be combined to give the estimate for the area. The individual components of the area totals are not normally divulged by the Potential Gas Committee for two reasons, the first being that the Committee's work is often based on confidential information shared with Committee members by employers and associates. It is this shared confidential information which gives a broader base of data and greater detail and credibility to the estimates of the Committee. However, the sharing of confidential information carries with it the requirement that the confidentiality is not compromised by releasing estimates for areas which are so small that the basic data would be indirectly revealed. The reporting areas chosen by the Potential Gas Committee are large enough that the confidentiality of information is protected and yet small enough to be geologically coherent. The second reason is that, particularly when dealing with estimates of resources in the speculative category, there may be a considerable range of uncertainty in the resource estimates for any individual basin, province or trend. By combining individual estimates for an entire area, it is hoped that overly optimistic individual estimates may be counterbalanced by other, more conservative, individual estimates and, thus, a realistic most likely estimate for the area can be achieved.

Limiting Considerations

The estimate presented here is limited to the contiguous United States, Alaska, and adjacent offshore areas. Hawaii, the island territories and their adjacent offshore areas are not included.

No potential supply of natural gas is included which exists at subsurface depths greater than 30,000 feet or, in offshore areas, where water depths are in excess of 1,000 meters (3,281 feet). Separate evaluations are made for the potential supply existing at onshore drilling depths from 0 to 15,000 feet and from 15,000 to 30,000 feet. These estimations recognize the greater technological and economic difficulty of recovering resources that exist below drilling depths of 15,000 feet. In offshore areas, estimates are made for the potential existing beneath water depths of 0 to 200 meters (656 feet) and 200 to 1,000 meters (3,281 feet). Estimates for water depths less than 200 meters essentially represent the potential supply that may be recovered from beneath the Continental Shelf whereas the estimates for water depths of 200 to 1,000 meters essentially represent resources that may be recovered from beneath portions of the Continental Slope.

The extension of Potential Gas Committee estimates to include offshore areas beneath water depths up to 1,000 meters (3,281 feet) is a significant increase from the previous depth limit of the 1968 through 1976 reports which included resource estimates out to a water depth of 1,500 feet. In the opinion of Committee members, there has been sufficient improvement in drilling, production and offshore pipeline technology to warrant this extension of limits in keeping with the Committee's concept of including all natural gas resources which could be produced in the future with normal advances in technology. There still remain questions as to the capability of completing pipeline connections in offshore water depths as great as 1,000 meters. The Committee has chosen, however, to be optimistic in its outlook and to present these estimates, recognizing that the above technical questions remain unanswered.

Estimates made by the Area Work Committees include resources which exist beneath areas presently withdrawn or proposed for withdrawal from exploration and development because of governmental action. Where there exists considerable potential beneath areas so withdrawn, it is appropriate for an estimate to be made of this potential and that estimate to be presented in the narrative portion of the report submitted by each Work Area.

Economic, technological and governmental policy considerations that are taken into account in the Potential Gas Committee's estimate of potential gas supply are related to (1) past production and proved reserves of natural gas, and (2) all wells which would be drilled in the future under the assumed conditions of adequate economic incentives in terms of price/cost relationships and current or foreseeable technology. Fundamental economic considerations — which include but are not limited to prices, costs, rates of take, recovery factors, abandonment pressures, etc. — are inherent in the definition of proved reserves: ". . . recoverable in the future from known oil and gas reservoirs under existing economic and operating conditions." Some gas that is actually present in known reservoirs is not producible because of the relationship between costs and prices, and therefore is not included in recoverable reserves.

Furthermore, there are other known gas accumulations of such small size that none of the gas can be produced in commercial quantities under " . . . existing economic and operating conditions." Such considerations result in proved reserves being something less than the total volumes of gas existing in known reservoirs. These same limitations are applicable to the estimates of potential supply. If a fundamental change in economics or technology occurs, estimates of potential supply will be changed accordingly.

The attribution technique presented in the Estimation of Potential Gas Supply section describes relationships between ultimately recoverable volumes of gas from known occurrences and prospective gas accumulations, after appropriate adjustment for variations in geological and reservoir conditions are made. The explicit assumption of adequate but reasonable prices and normal improvements in technology in the definition of potential supply relates to improvements in exploration and production techniques. Adequate prices, normal technological improvements and reasonable governmental policies are required to bring about the drilling necessary to prove the potential supply. These assumed conditions permit estimates of potential supply to be made by the Potential Gas Committee on the basis of relevant past history and experience concerning recovery factors, as well as the size and type of reservoirs which have been found, developed, and produced, without speculating as to future levels of prices and costs.

Historically, the Committee has largely excluded from its estimates the potential supply of natural gas from such nonconventional sources as geopressured-geothermal zones, gaseous coals, tight sands and certain brown shales, since the economics and technology of recovery from such sources had not yet been fully demonstrated. Technological developments and changing economic conditions in recent years have now affected certain of what had previously been considered nonconventional resources. In this report no potential supply of natural gas is included in the Committee's estimates which might be recovered from geopressured-geothermal brines of the U.S. Gulf Coast regions, directly from gaseous coal seams, or from gas hydrates. Where coals may have served as source beds for gas accumulations in conventional sandstone or limestone reservoirs, the potential resource contained in the conventional reservoir and recoverable by conventional drilling and production is included in the Committee's estimates. The potential resource from certain brown (Devonian) shales is largely excluded except that potential which the Committee believes to be recoverable by normal drilling and well stimulation and completion techniques and which is analogous in geologic setting to previous production. The natural gas potential from tight (low permeability) formations (including sandstone, shale and carbonate reservoirs) is included in the Committee's estimates to the extent that these resources fall within the limiting considerations for resource estimation. The inclusion of resources from tight gas sands of the Western states raises questions concerning the relationship of the estimates of the Committee to the estimates prepared by others for the resources in Western tight gas sands. No clear definition of the upper limits of what constitutes a tight gas sand has been given by most workers who have prepared estimates in the past. Some of the more recent estimates have included resources in formations with in situ effective permeabilities of up to 1 millidarcy. There may be overlap with the Committee's estimates since the Committee's limiting considerations would extend in some instances to resources in formations of less than 1 millidarcy permeability. Recognizing this potential overlap in estimates, the Committee intends to investigate this further during 1981 and 1982.

A review of nonconventional natural gas resources has been prepared by the Potential Gas Agency and is presented in Part II of this report. This review is in no way an independent appraisal by either the Potential Gas Committee or Potential Gas Agency of the volume of natural gas within nonconventional sources. Its purpose is merely to summarize the status of knowledge and the direction of research relative to nonconventional sources of natural gas and to present published estimates of the potential from such sources.

A review of potential resources of conventional natural gas in Canada has been prepared by the Canadian observers to the Potential Gas Committee based on the latest information available from the Geological Survey of Canada. Again, this review does not constitute an independent appraisal by either the Potential Gas Committee or the Potential Gas Agency. It is included as a service to the reader.

Estimate of Potential Supply of Natural Gas

TOTAL UNITED STATES

The potential supply of natural gas in the United States, excluding Hawaii and island territories, as of December 31, 1980, is estimated to be 193 trillion cubic feet in the *Probable* category, 358 trillion cubic feet in the *Possible* category, and 362 trillion cubic feet in the *Speculative* category (table 2). Figure 17 shows the geographic distribution of the potential supply as estimated by the Potential Gas Committee for each of the reporting areas for onshore and offshore resources.

Portions of this potential are less accessible than others due to technological and economic limitations. Recognizing the importance of accessibility, the potential resources have been summarized in table 3 by depth increments and by offshore water depth. The potential supply in Alaska is listed separately because of the unique conditions surrounding its accessibility to the United States market and because Alaska is in the early stages of exploration. In all tables, dashes are used to indicate estimated potential of less than 0.5 Tcf. All estimates are based on the volume of raw gas at 14.73 psia and 60° F.

Table 2 — Estimated potential supply of natural gas in United States by geographic areas as of December 31, 1980 (trillions of cubic feet at 14.73 psia and 60° F.)

Area		Probable	Possible	Speculative
A	Onshore	26	9	35
	Offshore	—*	—	16
B	Onshore	6	7	8
	Offshore	—	—	33
C	Onshore	—	2	1
D	Onshore	9	22	20
E	Onshore	6	16	—
	Offshore	19	40	—
G	Onshore	15	18	4
	Offshore	15	17	—
H	Onshore	40	78	69
I	Onshore	2	3	1
J-North	Onshore	27	66	42
J-South	Onshore	16	34	1
L	Onshore	4	9	15
	Offshore	—	8	9
	48 States Subtotal	185	329	254
K	Alaska—Onshore	6	16	28
	—Offshore	2	13	80
	Total United States	193	358	362

*In all tables, dashes are used to represent estimates of potential of less than 0.5 Tcf.

Table 3—Total estimated potential supply of natural gas by depth increments
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
Lower 48 States			
less than 15,000 feet	116	161	94
15,000 to 30,000 feet	35	103	102
	151	264	196
Alaska			
less than 15,000 feet	6	16	28
15,000 to 30,000 feet	—	—	—
	6	16	28
Total Onshore	157	280	224
Offshore (Water Depth)			
Lower 48 States			
less than 200 meters	32	43	35
200 to 1,000 meters	2	22	23
	34	65	58
Alaska			
less than 200 meters	2	13	68
200 to 1,000 meters	—	—	12
	2	13	80
Total Offshore	36	78	138
Total Lower 48 States	185	329	254
Total Alaska	8	29	108
Total United States	193	358	362

Probable Category

Within the onshore area of the lower 48 states, 77 percent of the Probable potential lies at drilling depths less than 15,000 feet and 23 percent lies at drilling depths between 15,000 and 30,000 feet. Eighty-two percent of the Probable potential is in onshore areas and 18 percent in offshore areas. Within the offshore area of the lower 48 states, 94 percent of the estimated Probable potential lies beneath water depths of less than 200 meters. Ninety-six percent of the total United States Probable potential is considered to exist within the lower 48 states and 4 percent in Alaska.

Possible Category

Within the onshore area of the lower 48 states, 61 percent of the estimated Possible potential lies at drilling depths less than 15,000 feet and 39 percent lies at drilling depths between 15,000 and 30,000 feet. Eighty percent of the Possible potential is in onshore areas and 20 percent in offshore areas. Within the offshore areas of the lower 48 states, 66 percent of the Possible potential lies beneath water depths less than 200 meters and 34 percent lies beneath water depths between 200 and 1,000 meters. The Possible potential for the lower 48 states is 92 percent of the total Possible potential supply while that for Alaska is 8 percent.

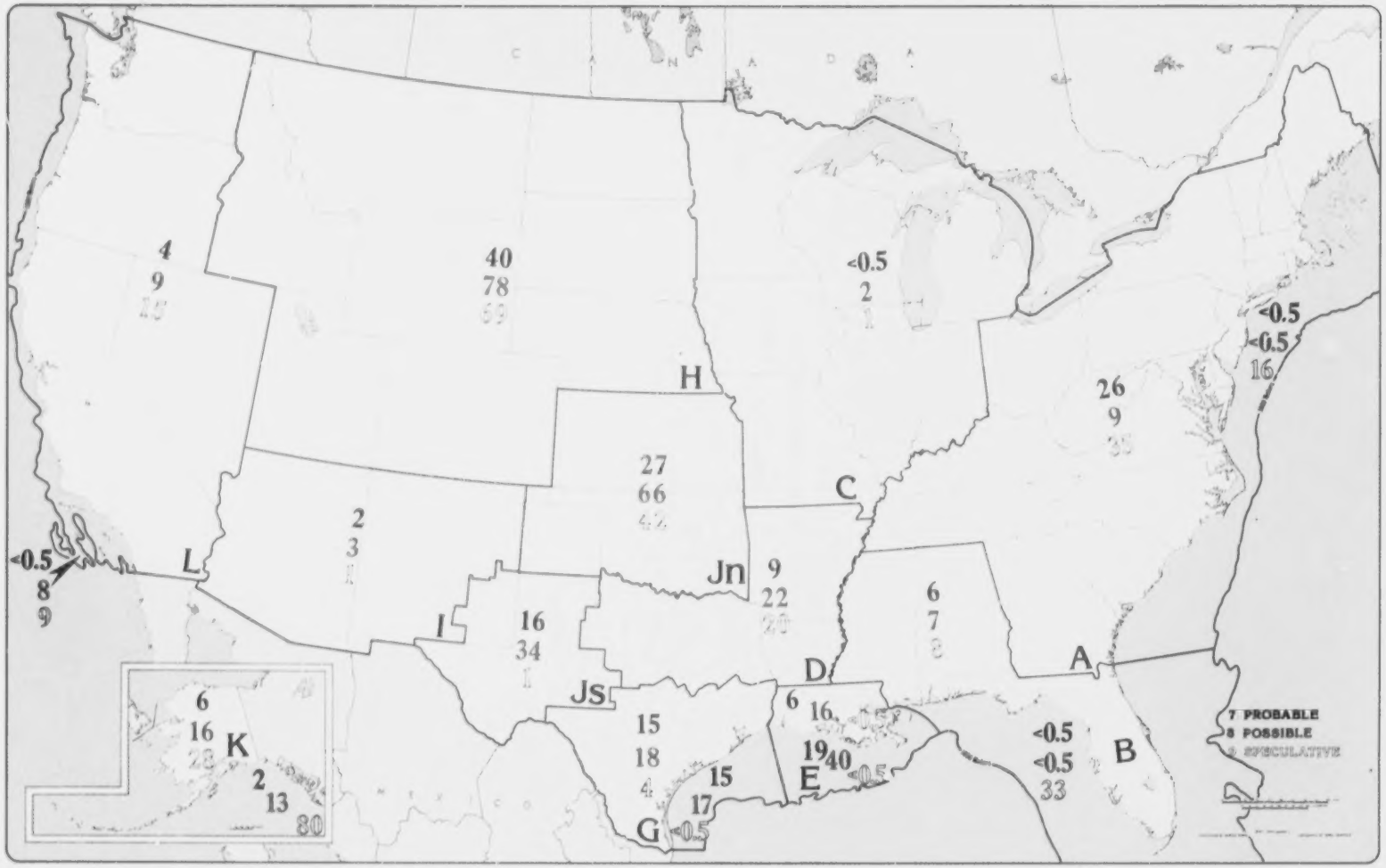


Figure 17 — Geographic distribution of potential supply as estimated by the Potential Gas Committee

Speculative Category

Within the onshore areas of the lower 48 states, 48 percent of the estimated Speculative potential lies at drilling depths less than 15,000 feet and 52 percent lies at drilling depths between 15,000 and 30,000 feet. The total potential onshore is 77 percent and 23 percent of the total potential Speculative supply for the lower 48 states lies offshore. In the offshore areas of the lower 48 states, 60 percent of the potential Speculative supply lies beneath water depths of less than 200 meters and 40 percent beneath water depths of 200 to 1,000 meters. The estimated Speculative supply for the lower 48 states is 70 percent of the total United States Speculative potential and the estimated Alaskan potential is 30 percent.

Comparisons with 1978 Report

This report reflects significant shifts in the pattern of distribution of estimated potential supply when compared to the report prepared for year-end 1978. For the lower 48 states onshore, 39 percent of the potential is estimated to lie at depths between 15,000 and 30,000 feet, compared to 32 percent of the potential in 1978. In spite of the decrease in the total estimated potential for the United States, the estimates for this deeper drilling (below 15,000 feet) have also been increased in terms of the actual estimated volume from 199 Tcf in 1978 to 240 Tcf in 1980. These increases in the estimates are the result of increased focus on exploration for deep targets and are made possible by better geophysical information and by the results of exploratory drilling in the deep portions of the sedimentary basins. Also for the lower 48 states, 20 percent of the total potential is estimated to occur offshore as compared to 26 percent in 1978. This represents a decrease in the actual estimated volumes from 216 Tcf in 1978 to 157 Tcf in 1980. The decreases in offshore areas of the lower 48 states were greatly influenced by the maturity of the Gulf Coast region in terms of exploration and production and by disappointing results of offshore exploration in the Baltimore Canyon area of the Atlantic offshore province. Alaska is now estimated to contain 16 percent of the U.S. potential compared to 19 percent in 1978. This reflects a decrease in the estimates of Alaskan potential from 189 Tcf in 1978 to 145 Tcf in 1980. The Alaskan decrease results from disappointing results in offshore areas, especially in the Gulf of Alaska, and re-evaluation of the potential of certain onshore basins.

AREA REPORTS

Area A: Ohio, Kentucky, Tennessee, Georgia, and All States Farther East and Adjacent Offshore

The potential supply of natural gas for Area A, which includes the Appalachian basin, the Triassic basins and the Offshore Atlantic, has been revised downward 35 Tcf from the report of 12/31/78. This is primarily a result of indications of a reduced natural gas potential of the U.S. Atlantic offshore region. Of the 29 offshore tests drilled since 1978, 23 were in the Mid-Atlantic (Baltimore Canyon) area, and 6 were in the South-Atlantic (Southeast Georgia Embayment) area. Significant hydrocarbon shows were present in five of the Mid-Atlantic wildcats, all of which were within a few miles of each other and approximately 100 miles off the New Jersey coast. While the natural gas potential of the Atlantic continental margins is diminished, industry indicates by decisive actions that the expensive search for economical accumulations of new reserves in the region will continue.

Onshore there has been an upward revision of natural gas potential because of significant successful wildcat drilling in Pennsylvania, West Virginia, Tennessee and Virginia in the Eastern Overthrust Belt. Testing is also anticipated for New York State in the Overthrust Belt which extends from Canada southward into Alabama and Georgia. In general, the Appalachian basin is in the early stages of a very important new exploratory campaign. Intensive geophysical surveys in the basin will almost certainly lead to new drilling programs. Natural gas potential may exist in the eastern portion of the Overthrust Belt, where a wedge of from 10,000 to 20,000 feet of clastic sedimentary rocks may be present, and, if these rocks are not metamorphosed, a virtually untested basin exists with an enormous volume of prospective rocks present.

Approximately 0.5 percent of the total region of Area A is being considered for RARE II classification and consequent withdrawal from oil and gas exploration and development. Judging by the very minor amounts of acreage so classified to date, it is the expectation that less than 0.1 percent of the proposed lands will be designated as RARE II. The potential areas, for the most part, are in the Eastern Thrust Belt or are underlain by metamorphics where the potential resource volumes are estimated to be relatively small per cubic mile of sediment. Therefore, the impact of RARE II acreage on the potential gas supply within Area A is negligible.

Table 4 — Area A. Eastern United States
Ohio, Kentucky, Tennessee, Georgia, and all states farther east
and adjacent offshore
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	26	9	24
15,000 to 30,000 feet	—	—	11
Total	26	9	35
Offshore (Water Depth)			
less than 200 meters	—	—	11
200 to 1,000 meters	—	—	5
Total	—	—	16
Area A total	26	9	51

Area B: Mississippi, Alabama, Florida, and Adjacent Offshore

There is little change in the estimates for natural gas potential for the southeastern states prepared for this report compared to the year-end 1978 report. In onshore areas there is a 1 Tcf decrease in the Possible potential for drilling depths less than 15,000 feet and an increase of 1 Tcf in each of the Possible and Speculative categories for drilling depths between 15,000 and 30,000 feet. There is no change in the estimates for the offshore area.

The changes in estimates of potential in onshore areas relate to new information gained from exploration and drilling activities. In the Black Warrior basin of northeastern Mississippi and northwestern Alabama, there continues to be strong interest in exploration and development of shallow Paleozoic fields. Most of the drilling in the Black Warrior basin has taken place in and around producing fields. The Hosston producing area of the Mississippi Salt basin is the dominant area of drilling activity in Area B. Approximately 60 wildcat wells have been drilled in this Hosston area in the past two years and 6 of these have been discoveries. Exploration for Jurassic objectives is receiving a boost with the drilling of a number of deep wells to test the Cotton Valley Formation in southern Mississippi. The discovery of the Bogalusa field in Washington Parish, Louisiana in '979 provided the impetus for increased Cotton Valley exploration in Mississippi.

The most significant discovery in recent years of gas from Jurassic strata is the completion in 1979 of an exploratory well drilled by Mobil in Mobile Bay, Alabama. Although the potential indicated by this discovery may be very large, no further developments of this prospective area had taken place by the end of 1980 and it is too early to assess the impact of this discovery on estimates of potential supply.

There has been no exploration or drilling activity in the offshore portion of Area B and there are no new data available on which to base a revision of the estimates of offshore potential.

Table 5 — Area B. Southeastern United States
Mississippi, Alabama, Florida and adjacent offshore
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	4	4	3
15,000 to 30,000 feet	2	3	5
Total	6	7	8
Offshore (Water Depth)			
less than 200 meters	—	—	20
200 to 1,000 meters	—	—	13
Total	—	—	33
Area B total	6	7	41

Area C: Minnesota, Wisconsin, Michigan, Iowa, Illinois, Indiana, and Missouri

Area C comprises the Michigan basin, the Illinois basin and the Forest City basin. The estimates of potential gas supply have been revised downward a total of 1 Tcf since the December 31, 1978 report mainly because of transfer from potential resources to proved reserves. Discoveries resulting in additions to proved reserves have occurred in the Michigan basin where exploration for Middle Silurian Niagaran pinnacle reefs has met with continued success in producing both oil and gas discoveries. Approximately 550 productive reefs have been found in the northern reef trend. Niagaran reefs currently supply 81% of Michigan's total oil production and 89% of the gas production.

The main exploration emphasis in the Michigan basin is directed toward finding the Niagaran pinnacle reefs. In addition, there is increased interest in exploring the Central basin area where deeper drilling on known Mississippian and Devonian structures has been rewarded mainly with oil pays in the Devonian Richfield interval. Indications of gas shows from the Ordovician Trenton-Black River Formation in north central Michigan has generated renewed interest in finding more production from fractured carbonate rocks in this prolific producing interval.

Oil and gas drilling activity in the Illinois portion of the Illinois basin almost doubled in 1980 from a comparable period in 1979. The increased drilling does not appear to be the result of any particular "play" but rather of infill drilling and the extension of production in old areas. The trend has been to deeper drilling in established producing areas where wells have been deepened to test mainly the Mississippian Salem and Warsaw Formations. In some cases excellent wells have been found by deepening to the Devonian Dutch Creek Formation. The new production, which has been entirely oil with very little associated gas, has been concentrated in southeastern Illinois in Wayne and White Counties.

In the Indiana portion of the Illinois basin, oil and gas drilling activity increased in 1980 over 1979. The activity has been concentrated in southwestern Indiana where deeper drilling to the limestones and sandstones of the Mississippian has resulted in mainly oil production with very little associated gas.

Exploration in the Forest City basin has been confined to the west central Missouri area where 500 wells have been permitted to test for shallow heavy oil in the Pennsylvanian Cherokee and Blue Jacket Formations. Oil production is expected to double from 90,000 barrels produced during 1979, however, there has been no metered gas production.

Table 6 — Area C, North Central United States
Minnesota, Wisconsin, Michigan, Iowa, Illinois, Indiana, and Missouri
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	—	2	1
15,000 to 30,000 feet	—	—	—
Area C total	—	2	1

Area D: Arkansas, North Louisiana, and Central Texas (RR Comm. Dists. 5, 6, 7B and 9)

From the standpoint of prospective areas, Area D includes the North Louisiana, East Texas, Fort Worth and Hardeman geologic basins as well as the southern part of Arkansas, south of the Ouachita System forelands. The estimate of potential supply of natural gas remains essentially unchanged compared to the report of 12/31/78. The estimates have been increased by 1 Tcf in the Probable category and 2 Tcf in the Possible category, but decreased by 2 Tcf in the Speculative category.

In the past two years there have been significant discoveries in the Fort Worth basin and in the Smackover Formation along the Louisiana-Arkansas state border. These discoveries and additional geologic and drilling information have led to re-evaluation of the potential supply and to shifts from the Speculative category and increases in the Possible and Probable categories. Discoveries have also resulted in the shift of some former potential supply into proved reserves.

The estimates of potential supply also include some resources which are believed to occur in the tight formations of the Travis Peak and Cotton Valley, especially in the East Texas basin. Some of this estimated potential probably falls within the current definition of tight formations of the Federal Energy Regulatory Commission.

Table 7 — Area D. Arkla-Tex
Arkansas, North Louisiana, and Central Texas
(RR Comm. Dists. 5, 6, 7B & 9)
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	9	22	16
15,000 to 30,000 feet	—	—	4
Area D total	9	22	20

Area E: South Louisiana and Offshore Louisiana

Area E consists of the onshore area of south Louisiana and the offshore area of Louisiana out to a water depth of 1,000 meters. The estimate of potential supply of natural gas from Area E has been decreased by 17 Tcf from the estimate of 12/31/78. The new estimate of the total potential supply for this area is 81 Tcf.

About one-third of the decrease in estimates is related to transfers from potential supply to proved reserves in this actively developing area. The net result of evaluation of new data and reappraisal of earlier estimates accounts for the remainder of the decrease.

Although the net results of re-evaluation of this area have been a decrease in the estimates of potential supply, one part of the Area has been estimated to have a greater potential than was estimated for previous reports. This is the deep Tuscaloosa trend which extends in a belt approximately 20 miles wide and 300 miles long from Texas to Mississippi across the northern portion of south Louisiana. The Tuscaloosa trend, in which the exploratory target is the lower Tuscaloosa Formation of Cretaceous age and probable deltaic origin, is still supporting active exploratory activity even after five years of furious drilling activity. The success ratio has dropped, however, from nearly 100% initially to 20% in 1980. Most of the discoveries to date have been concentrated in the center of the trend near Baton Rouge on what has been termed the "mega structure", a structural complex 20 miles long and 15 miles wide. The ultimate potential of this trend is not yet completely evaluated, but it appears significant.

Area E has produced approximately 25% of the total cumulative U.S. gas production and is presently producing about 35% (7 Tcf in 1979) of the current U.S. production.

Table 8 — Area E. South Louisiana and adjacent offshore
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	3	5	—
15,000 to 30,000 feet	3	11	—
Total	6	16	—
Offshore (Water Depth)			
less than 200 meters	18	27	—
200 to 1,000 meters	1	13	—
Total	19	40	—
Area E total	25	56	—

Area G: Texas Gulf Coast and South Texas (RR Comm. Dists. 1, 2, 3 and 4) and Adjacent Offshore

Area G includes south Texas and the Texas Gulf Coast, both onshore and offshore. The estimate of total potential supply for this Area has been reduced by 16 Tcf from the estimate of 12/31/78. This reduction in the estimates consists of 3 Tcf each in the onshore and offshore Probable category, 4 Tcf in the onshore Possible category and 6 Tcf in the offshore Possible category. There is no change in the estimate of Speculative potential. The changes are the net result of re-evaluation of the Area where considerable information is now available and transfers of discoveries from potential resources to proved reserves. About one-eighth of the decrease is related to transfers to proved reserves.

The main area of exploratory and drilling activity onshore in Area G is the Austin Chalk (Upper Cretaceous) play in the Giddings field area which stretches through Fayette, Lee and Burleson Counties. Offshore, several wells have been drilled to depths below 15,000 feet in the Brazos area.

Table 9 — Area G. Texas Gulf Coast and South Texas (RR Comm. Dists. 1, 2, 3 & 4) and adjacent offshore (trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	13	15	2
15,000 to 30,000 feet	2	3	2
Total	15	18	4
Offshore (Water Depth)			
less than 200 meters	14	12	—
200 to 1,000 meters	1	5	—
Total	15	17	—
Area G total	30	35	4

Area H: North and South Dakota, Nebraska, Montana, Wyoming, Idaho, Colorado, and Utah

Area H comprises the Rocky Mountain states and adjacent High Plains areas. The boundary of this area, and the adjacent Area L, have been modified with this report to place the State of Idaho in Area H. This change has been made in order to emphasize the close relationship of the geology of eastern Idaho to the Rocky Mountain area in general and because of the strong possibility of gas occurrences in Idaho similar to those in the currently developing Western Thrust Belt in Wyoming and Utah. Adjustments in the estimates in some comparative tables have been made to reflect this change.

Estimates of the natural gas potential for Area H have been increased from the 12/31/78 estimates by 17 Tcf in the Probable category and 6 Tcf in the Speculative category. The estimates for the Possible category have been reduced by 11 Tcf. This is a net increase of 12 Tcf overall.

Changes in the Probable category were made as a result of new evaluations, particularly in the Green River, Uinta, Piceance and Wind River basins. Decreases in the Possible category were largely the result of transfers from the Possible to the Probable category in the Wind River basin and re-evaluation and some transfer from Possible to Probable and proved reserves in the Central Thrust Belt. The increase in the Speculative category is the net result of additions in Montana and the Green River basin and re-evaluation and transfers to other categories in the Thrust Belt.

Considerably more information is now available upon which to base the estimate of the potential gas resources in the Western Thrust Belt than was available at the time of preparation of the estimate of 12/31/78. The estimates for the Probable category are now quite firm because of new discoveries and new geologic and engineering data. The estimates for Possible and Speculative categories are, of course, less assured than those for the Probable category, but are still much firmer than in 1978. The estimates are increased by 3 Tcf in the Probable category and decreased 9 Tcf in the Possible category and 6 Tcf in the Speculative category. Additions to proved reserves, as well as careful re-evaluation based on new data, have resulted in the changes. Also, shifts in the postulated depth of occurrence of the resource have been made based on new data. All of the estimated Probable potential is considered to be in the Central Thrust Belt along with most of the Possible potential and much of the Speculative potential. A large part of the Speculative potential in the Central Thrust is believed to lie in sub-thrust beds of Permian and Cretaceous age. Some Possible and Speculative potential is considered to lie in both the northern and southern parts of the Thrust Belt.

The estimates for the Western Thrust Belt are:

	Probable	Possible	Speculative
	(Tcf)	(Tcf)	(Tcf)
Less than 15,000 ft. drilling depth	5	18	17
Greater than 15,000 ft. drilling depth	4	18	26
	9	36	43

Total potential supply: 88 Tcf

Current drilling and development in the Wind River, Green River, and Uinta and Piceance basins includes some gas from tight formations which fall within current Federal Energy Regulatory Commission definitions of gas from tight formations. Some potential resources included in the Potential Gas Committee's estimates for these same basins would also fall within some definitions of gas from tight formations.

In the Wind River, Big Horn, Powder River, Green River and Uinta-Piceance basins, a few to several percent of the total land area is withdrawn from petroleum exploration due to governmental restrictions, but most or all of the withdrawn area may contain potential gas supply. Therefore, within these basins a small percentage of the estimated potential supply is affected. In the central and northern segments of the Western Thrust Belt, large parts (up to 50%) are included in withdrawn areas and, therefore, a large percentage of the estimated potential supply may be affected.

Table 10 — Area H. Northern Rocky Mountains
North and South Dakota, Nebraska, Montana, Wyoming, Idaho, Colorado, and Utah
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	30	49	29
15,000 to 30,000 feet	10	29	40
Area H total	40	78	69

Area I: Arizona and New Mexico

The estimates of potential gas supply for Area I have not changed appreciably during the past two years. Exploratory drilling has been minimal, with the greatest drilling emphasis being the infill of the Dakota and Mesaverde Formations in the San Juan basin.

The results of the exploratory drilling which has occurred have been negative. A wildcat test in the Rio Grande rift some 12 miles south of Albuquerque has been plugged and abandoned at a depth of 25,000 feet. However, the operator is planning another test to be drilled some distance northwest of Albuquerque to an estimated total depth of 19,700 feet.

Phillips Petroleum Company recently completed the drilling of a frontier effort, the Arizona State A-No. 1, Pinal County, to test the possible extension of the Western Thrust Belt into southern Arizona. Granite was entered at about 4,000 feet and drilling was terminated at a depth of approximately 18,000 feet still in the granite, and no hydrocarbon shows were encountered. It was hoped the well would penetrate the granite and reach younger sedimentary rocks below. The drilling rig will be moved to a site about 4 miles east of Tombstone, Arizona, where another deep exploratory well will be drilled.

Table 11 — Area I. Southern Rocky Mountains
Arizona and New Mexico
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	2	3	1
15,000 to 30,000 feet	—	—	—
Area I total	2	3	1

Area J-North: Mid-Continent (Kansas, Oklahoma, and Texas RR Comm. Dist. 10)

There are decreases in the estimates of potential supply for all categories in Area J-North compared to the estimates for 12/31/78. The total decrease in estimates amounts to 8 Tcf, most of which is accounted for by transfers from potential supply to proved reserves.

Exploratory activity is high in all parts of Area J-North, especially in the deep part of the Anadarko basin. At year-end 1980 there were about 350 locations which were either drilling to below 15,000 feet or had been projected to drill below 15,000 feet. Of these, over 50 were tests to 20,000 feet or deeper and four were projected to 26,000 feet or deeper. The overall deep drilling activity was running 75% ahead of the record pace set in 1979.

Approximately a third of this drilling activity was targeted toward Springer (Mississippian/Pennsylvanian) sand objectives. Early results indicate that by the next report much of the potential supply allocated to these zones will be transferred from the Possible category to the Probable category and proved reserves.

Table 12 — Area J-North. Mid-Continent
Kansas, Oklahoma, and Texas RR Comm. Dist. 10
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	18	27	5
15,000 to 30,000 feet	9	39	37
Area J-North total	27	66	42

Area J-South: Permian Basin (S.E. New Mexico, Chaves, Eddy, Lea & Roosevelt Cos. and Texas RR Comm. Dists. 7C, 8 and 8A)

The estimates of the potential gas resource for Area J-South have been reduced in the Possible category, both shallow and deep, by 2 Tcf compared with the estimates of 12/31/78. All of this decrease can be accounted for by transfers from potential resources to proved reserves.

Over the past five years up to 1979, additions to proved reserves have averaged about 0.75 Tcf per year. In 1979, additions to proved reserves totaled slightly more than 1.5 Tcf. Estimates of additions to proved reserves for 1980 are not available at the time of printing.

Table 13 — Area J-South, Permian Basin
(S.E. New Mexico, Chaves, Eddy, Lea & Roosevelt Cos. and Texas RR Comm. Dists. 7C, 8 & 8A)
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	8	19	1
15,000 to 30,000 feet	8	15	
Area J-South total	16	34	1

Area K: Alaska and Adjacent Offshore

The 1980 estimates of potential gas resources for Alaska are approximately 30% lower than those reported in 1978. The 1978 and 1980 figures are summarized below:

	Probable	Possible	Speculative
	(Tcf)	(Tcf)	(Tcf)
1980	8	29	108
1978	13	40	136

This downward trend in estimates is not surprising, considering the nature of exploration in such a vast frontier as Alaska, a state of 357 million acres on land and another 380 million acres between the shoreline and the 1,000-meter water depth. In the late 1960's when the Potential Gas Committee first started making estimations in Alaska, little was known about the limits of the sedimentary basins and their hydrocarbon potential. Optimism overshadowed the lack of data.

Alaska is still in a frontier mode, but there are better interpretations now about both limits and potentials. Recent seismic work and wildcat drilling have diminished what was earlier considered to be prospective acreage, for example, portions of the Arctic basin, the Gulf of Alaska and the Lower Cook Inlet. Negative results of exploratory activity in the Kodiak area and Northern Gulf of Alaska have also resulted in reduction of estimates of potential gas resources.

A number of wildcat wells have been drilled recently in the National Petroleum Reserve-Alaska, but this area is still considered to contain potential for development of gas resources. There are a number of large areas like the Bering Sea, Arctic Wildlife Refuge, Norton basin and Chukchi Sea that, as yet, have never been drilled for oil or gas. These frontier areas could hold unknown potential as could portions of such already partially drilled areas as the Arctic and Cook Inlet basins.

Table 14 — Area K. Alaska and adjacent offshore
(trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	6	16	28
15,000 to 30,000 feet	—	—	—
Total	6	16	28
Offshore (Water Depth)			
less than 200 meters	2	13	68
200 to 1,000 meters	—	—	12
Total	2	13	80
Area K total	8	29	108

Area L: California, Nevada, Pacific Northwest (excluding Idaho), and Adjacent Offshore

Area L includes the Pacific Coast states, onshore and offshore, and the State of Nevada. Idaho, which was formerly included in the estimates for Area L, is now included in Area H. Estimates for Area L remain essentially the same as for 12/31/78 in the Probable and Possible categories when the transfer of Idaho potential is taken into account. There is a slight increase (2 Tcf) in the estimate of the onshore potential, both deep and shallow.

Exploration activity in the onshore California basins remained at relatively low levels in the past two years except for the Sacramento Valley. In the Sacramento Valley the most significant developments were at South Oakley, deeper zones at North Lindsey Slough and extensions of production south of Grimes in the College City area. There were also a large number of extensions and lesser new field discoveries, some of which could become more significant with additional development. Deeper exploration in the Southern San Joaquin Valley continues and more activity is scheduled for the future. This remains one of the more eagerly sought objectives on the west coast. Other onshore basins in California had only limited exploration activity with new gas largely limited to solution gas associated with new oil discoveries.

The discovery of the Mist field in Columbia County gave Oregon its first production of natural gas. This discovery, made in 1979, has produced an increase in drilling in nearby areas as well as in other basins in Oregon and some in Washington. There has been an even greater land play in both states and the pace of exploration will increase in the next few years. Additional discoveries are a reasonable expectation. The increase in the Speculative category is a result of the initial discovery of gas in Oregon. The significance of this discovery is not yet great enough to make a measurable change in the Probable and Possible categories.

In the offshore area, exploration drilling on the tracts awarded in the 1979 OCS sale has been slow in getting underway because of governmental permit delays and no discoveries have been announced to date. Considerable seismic activity has taken place in the offshore Santa Maria area in anticipation of a proposed OCS sale. As a result of discoveries made on tracts from earlier sales in the eastern Santa Barbara Channel and the San Pedro Bay areas, some gas was transferred to proved reserves.

Table 15 — Area L. California, Nevada, Pacific Northwest (excluding Idaho), and adjacent offshore (trillion cubic feet)

	Probable	Possible	Speculative
Onshore (Drilling Depth)			
less than 15,000 feet	3	6	12
15,000 to 30,000 feet	1	3	3
Total	4	9	15
Offshore (Water Depth)			
less than 200 meters	—	4	4
200 to 1,000 meters	—	4	5
Total	—	8	9
Area L total	4	17	24

In Retrospect and Prospect

As for all resources occurring in the crust of the earth, the absolute volume of natural gas ultimately recoverable is a specific but unknown quantity. It should be recognized that changes in estimates of the potential supplies from time to time do not actually increase or decrease the ultimately recoverable volume. Such changes reflect improvements in estimating techniques and increased basic knowledge of the occurrence of natural gas at the time of the estimate. It must also be recognized that any estimate of potential supply lacks the accuracy of the estimates of proved recoverable reserves.

Economic, technological and governmental factors do not change the absolute volume of ultimately recoverable natural gas. Such factors, however, do influence the estimates of the potential supply in that they may increase or decrease the amount of gas which the estimator feels are within the limits of economic and technological feasibility. These factors may further influence the timing and rate of development of natural gas resources.

In each succeeding study by the Potential Gas Committee, the impact of new technology has been considered. In the first study of 1964, offshore drilling was limited to water depths of 300 feet. In 1966, this limit was increased to 600 feet, and in 1968, the water depth was increased further to 1,500 feet. Drilling depths were increased also, from 25,000 to 30,000 feet, in the 1968 report. The parameters of maximum drilling depth of 30,000 feet and 1,500 feet water depth were used for the 1970, 1972, and 1976 reports. The parameters for the 1978 and 1980 publications retain the onshore maximum drilling depth of 30,000 feet. In offshore areas, separate estimates are made for resource potential existing beneath water depths of 0 to 200 meters (656 feet) and 200 to 1,000 meters (3,281 feet). All potential supply estimates represent most likely volumes. The effects of newly developed technology will continue to be considered in future studies.

Table 16 summarizes the estimates of potential supply which have been given in each of the Potential Gas Committee reports.

Changes in estimates in each of the categories represent re-evaluation based on additional drilling. As drilling progresses, gas volumes estimated to be in a particular reservoir will move from one category to another as shown schematically in figure 18. Since any projection of potential supply lacks the accuracy of proved reserve figures, particularly in the Speculative category, it must be recognized that these estimates of potential supply will be subject to upward and downward revisions as new geological and engineering data are provided by exploratory drilling.

Table 16 — Comparison of estimates of potential supply of natural gas from Potential Gas Committee reports (trillions of cubic feet at 14.73 psia and 60° F.)

	Probable	Possible	Speculative	Total
Lower 48 States				
As of 12-31-66	300	210	180	690
As of 12-31-68	238	317	245	800
As of 12-31-70	218	326	307	851
As of 12-31-72	212	290	278	780
As of 12-31-76	192	318	188 to 238	698 to 748
As of 12-31-78	186	359	285	830
As of 12-31-80	185	329	254	768
Total United States (including Alaska)				
As of 12-31-68	260	335	632	1,227
As of 12-31-70	257	387	534	1,178
As of 12-31-72	266	384	496	1,146
As of 12-31-76	215	363	345 to 395	923 to 973
As of 12-31-78	199	399	421	1,019
As of 12-31-80	193	358	362	913

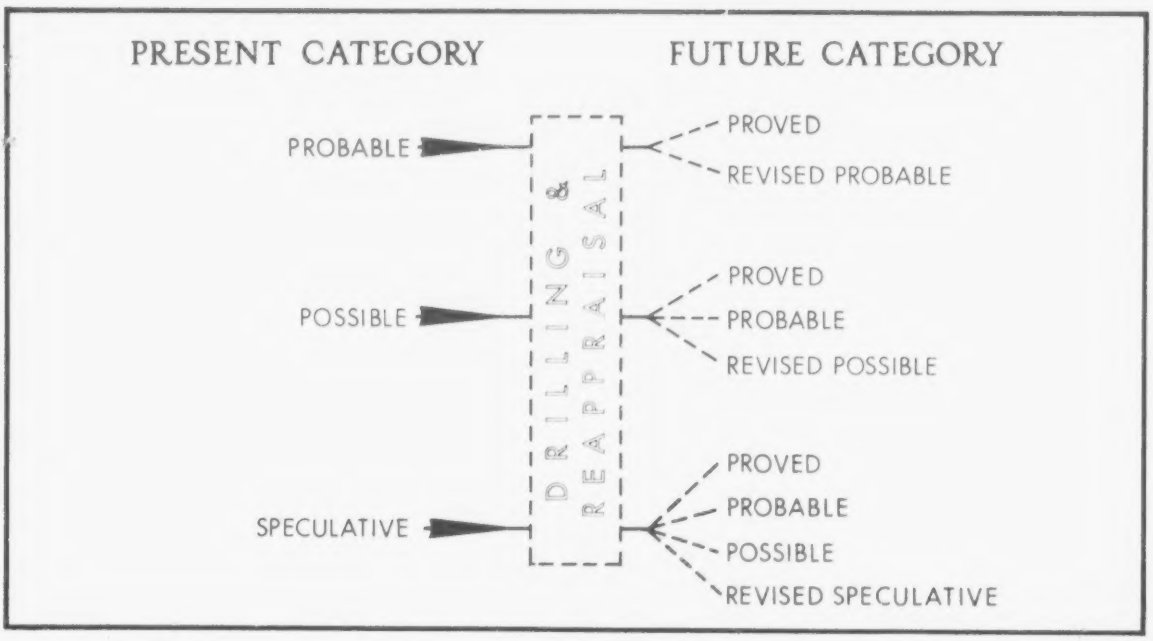


Figure 18—Schematic representation of progression of potential gas supplies as a result of drilling and reappraisal

Tables 17 through 20 contain estimates of potential for each Area broken out by drilling depth increments and by offshore water-depth divisions.

Table 17 — Estimated potential supply of natural gas in United States as of December 31, 1980

Onshore, 0-15,000 feet drilling depth
(trillions of cubic feet at 14.73 psia and 60° F.)

Area	Probable	Possible	Speculative
A	26	9	24
B	4	4	3
C	—	2	1
D	9	22	16
E	3	5	—
G	13	15	2
H	30	49	29
I	2	3	1
J-North	18	27	5
J-South	8	19	1
L	3	6	12
48 States Subtotal	116	161	94
K Alaska	6	16	28
Total less than 15,000 feet Drilling Depth Onshore United States	122	177	122

Table 18 — Estimated potential supply of natural gas in United States as of December 31, 1980

Onshore, 15,000-30,000 feet drilling depth
(trillions of cubic feet at 14.73 psia and 60° F.)

Area	Probable	Possible	Speculative
A	—	—	11
B	2	3	5
C	—	—	—
D	—	—	4
E	3	11	—
G	2	3	2
H	10	29	40
I	—	—	—
J-North	9	39	37
J-South	8	15	—
L	1	3	3
48 States Subtotal	35	103	102
K Alaska	—	—	—
Total 15,000 to 30,000 feet Drilling Depth Onshore United States	35	103	102

Table 19 — Estimated potential supply of natural gas in United States as of December 31, 1980

Offshore, 0-200 meters water depth
(trillions of cubic feet at 14.73 psia and 60° F.)

Area	Probable	Possible	Speculative
A	—	—	11
B	—	—	20
C	—	—	—
D	—	—	—
E	18	27	—
G	14	12	—
H	—	—	—
I	—	—	—
J-North	—	—	—
J-South	—	—	—
L	—	4	4
48 States Subtotal	32	43	35
K Alaska	2	13	68
Total less than 200 meters Water Depth Offshore United States	34	56	103

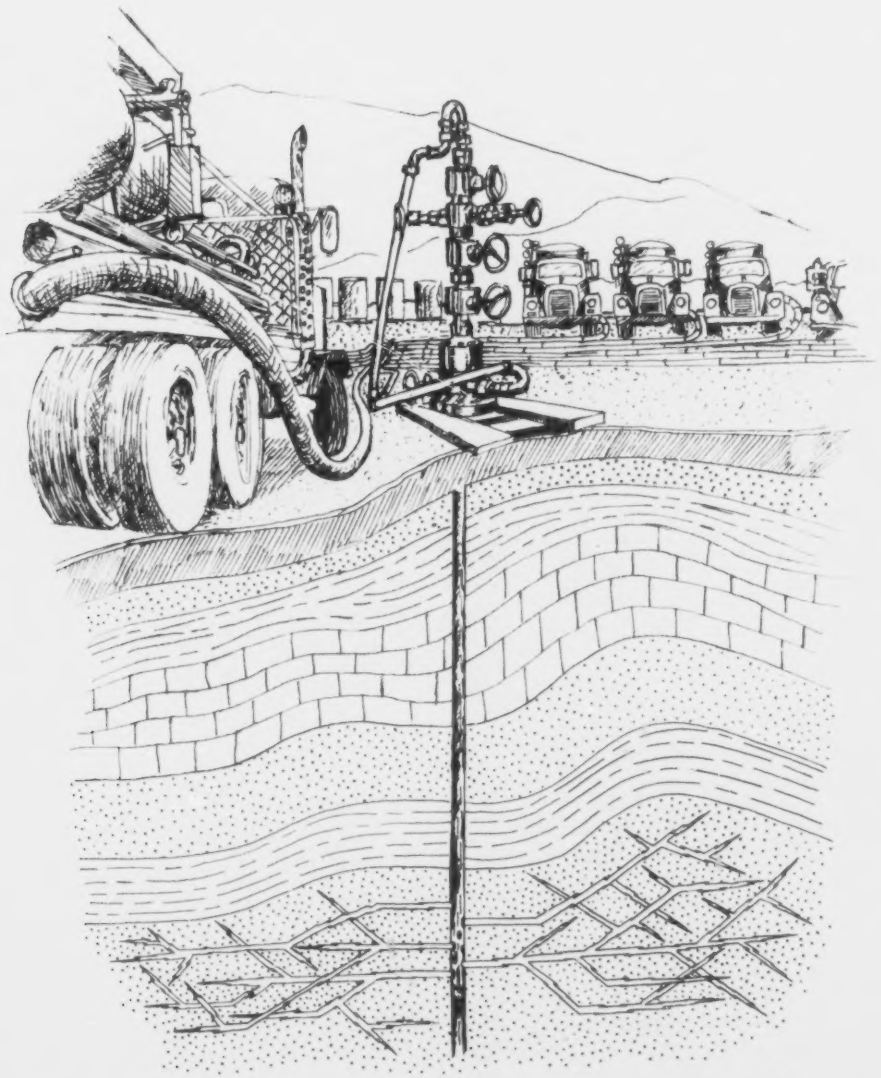
Table 20 — Estimated potential supply of natural gas in United States as of December 31, 1980

Offshore, 200-1,000 meters water depth
(trillions of cubic feet at 14.73 psia and 60° F.)

Area	Probable	Possible	Speculative
A	—	—	5
B	—	—	13
C	—	—	—
D	—	—	—
E	1	13	—
G	1	5	—
H	—	—	—
I	—	—	—
J-North	—	—	—
J-South	—	—	—
L	—	4	5
48 States Subtotal	2	22	23
K Alaska	—	—	12
Total 200 to 1,000 meters Water Depth Offshore United States	2	22	35

PART II

REPORT OF THE POTENTIAL GAS AGENCY



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REPORT OF THE POTENTIAL GAS AGENCY

Evaluation by Potential Gas Agency

—Harry C. Kent, Director
Potential Gas Agency, Colorado School of Mines

The accompanying report by the Potential Gas Committee (PGC) is the eighth estimate of the potential supply of natural gas in the United States made by the Committee and the seventh published by the Potential Gas Agency (PGA) of the Colorado School of Mines. The estimates contained in this report have been prepared by members of the Potential Gas Committee working through their Area Work Committees and reviewed at the regional and national level by the entire Potential Gas Committee. The Potential Gas Agency has acted to guide and assist the work of the Potential Gas Committee and to assure that professional standards and objectivity were maintained during the preparation of the estimates.

A report on the potential resources of natural gas from nonconventional sources is included in Part II of this publication. It represents a review of the information available to the Potential Gas Agency to the time of publication. It is not an independent evaluation of the potential of these resources by either the Potential Gas Committee or the Potential Gas Agency but it is an attempt to consolidate a brief review of potential nonconventional resources of natural gas currently being investigated in this country. This report was prepared in the offices of the Potential Gas Agency by James C. Donaldson and James J. Emme, and it was reviewed by a number of experts in the respective fields who are credited at the beginning of the report.

A second report, and a new addition to the biennial reports on potential supply of natural gas in the United States, is a review of the potential resources of conventional natural gas in Canada. This review was prepared by Donald W. Axford and A. A. Wilkins, who are the Canadian observers to the Potential Gas Committee, and is included in Part III of the report. Data contained in the review are taken entirely from Geological Survey of Canada Open-File Release No. 767, prepared by R. M. Procter, P. J. Lee and D. N. Skibo and released in March 1981.

DUTIES AND RESPONSIBILITIES OF POTENTIAL GAS AGENCY

The Potential Gas Agency is charged with approving the criteria and methods used by the Potential Gas Committee and insuring that these are followed and maintained in preparing estimates and reports; the object being to maintain the highest scientific standards and objectivity. The Agency also acts to assure that there is an adequate representation of qualified personnel from many different segments of the natural gas industry and governmental and academic sectors. The Agency appoints the Chairman and Vice Chairman of the Potential Gas Committee and approves the appointment of other members to the Committee.

The Agency is sponsored by the American Gas Association through a grant to the Colorado School of Mines. The School of Mines, in turn, is responsible for selecting the Director and other personnel of the Agency and conducting the affairs of the Agency in a professional manner. Guidance for the PGA is provided by the Gas Supply Committee of the American Gas Association, which is responsible for the setting of general policy and objectives and financing of the study.

ORGANIZATION AND OPERATION OF POTENTIAL GAS COMMITTEE

There is no direct link between the Gas Supply Committee of the American Gas Association and the Potential Gas Committee. All contact is through the Potential Gas Agency. One of the duties of the Agency is to see that separation is maintained. The significance of this separation is that the Gas Supply Committee does not, in any way, enter into the deliberations nor influence the estimates which are prepared by the PGC.

Membership of the Potential Gas Committee is drawn from both large and small exploration and production companies, consultants, state geological surveys, and academic institutions. Most of the members are geologists and engineers. Observers from a number of Federal agencies and various associations are also included in the committee membership. For administrative purposes, the United States is divided into three regions (East, Central and West) and into 12 Work Areas. Each of the Work Areas has a Chairman, whose appointment must be approved by the Potential Gas Agency, and who reports to a Regional Vice Chairman. The Work Area Committees must also include at least one representative each from the pipeline and distribution segments of the natural gas industry in order to assure broad representation of all interests.

Each Area Work Committee functions independently. Its members are charged with gathering all available information about the geology and occurrence of natural gas in the assigned area. The members review past exploration and production history and, based on the historic record and their collective geological and operating expertise, evaluate the potential for further discoveries in both partially explored and unexplored basins.

The procedures for arriving at the estimates of potential supply are outlined in detail in Part I of this report. The Director and other staff members of the Potential Gas Agency have met with Area Work Committees and have observed their operation. It is the conclusion of the Agency that the Area Work Committees have followed the standards adopted by the Potential Gas Committee, as outlined in Part I, in preparing their estimates.

Because of the nature of the work involved, it is not always possible to achieve complete uniformity in the work of all of the Area Committees. In some areas, there is a great deal of geologic knowledge and the area is in a reasonably mature stage of exploration. In other areas, exploration has only begun and there is relatively little basic geologic information. In spite of these differences, in the opinion of the Potential Gas Agency, the work of the Committee has been conducted in a sound and scientific manner.

Although the only way in which the estimates of the Committee can be proved or tested is by drilling prospective areas, the variety of background of individuals working on the Committee and the discussion and review which have occurred at both the area and national levels have resulted in a consensus. Over the past 17 years several hundred qualified professionals have participated in the work of the Potential Gas Committee. The consistency of the results of these investigations within the parameters set by the Committee is notable. Although there may be differences of opinion as to the potential in limited local areas or basins, the resulting figures are reasonable estimates when reported as composite figures for Potential Gas Committee reporting areas.

REVIEW OF PROVED RESERVES AND POTENTIAL SUPPLY

As emphasized in the report of the Potential Gas Committee, the estimates presented by this Committee are of potential supply which is in addition to proved reserves. In order to gain a total perspective of the potential ultimately recoverable volume of natural gas in the United States, it is necessary to consider the total of cumulative past production, present proved reserves, and future supply. Cumulative natural gas production for each of the PGC reporting areas, taken from the published report of the Committee on Natural Gas Reserves of the American Gas Association as of December 31, 1979, is shown in figure 19. Also shown in figure 19 are estimates of proved natural gas reserves for each of the Potential Gas Committee reporting areas, based on estimates published by the A.G.A. Committee on Natural Gas Reserves as of December 31, 1979. Estimates of cumulative production and proved reserves for year-end 1980 are not available at the date of publication.

The report of December 31, 1979 prepared by the Committee on Natural Gas Reserves of the American Gas Association was the last report prepared by that committee following the procedures of past years and published jointly with reports of the American Petroleum Institute and the Canadian Petroleum Association. In February 1980 the first of a new series of reports on U.S. Crude Oil and Natural Gas Reserves was issued by the Office of the Oil and Gas Information System, Energy Information Administration, U.S. Department of Energy. This report compiled estimates

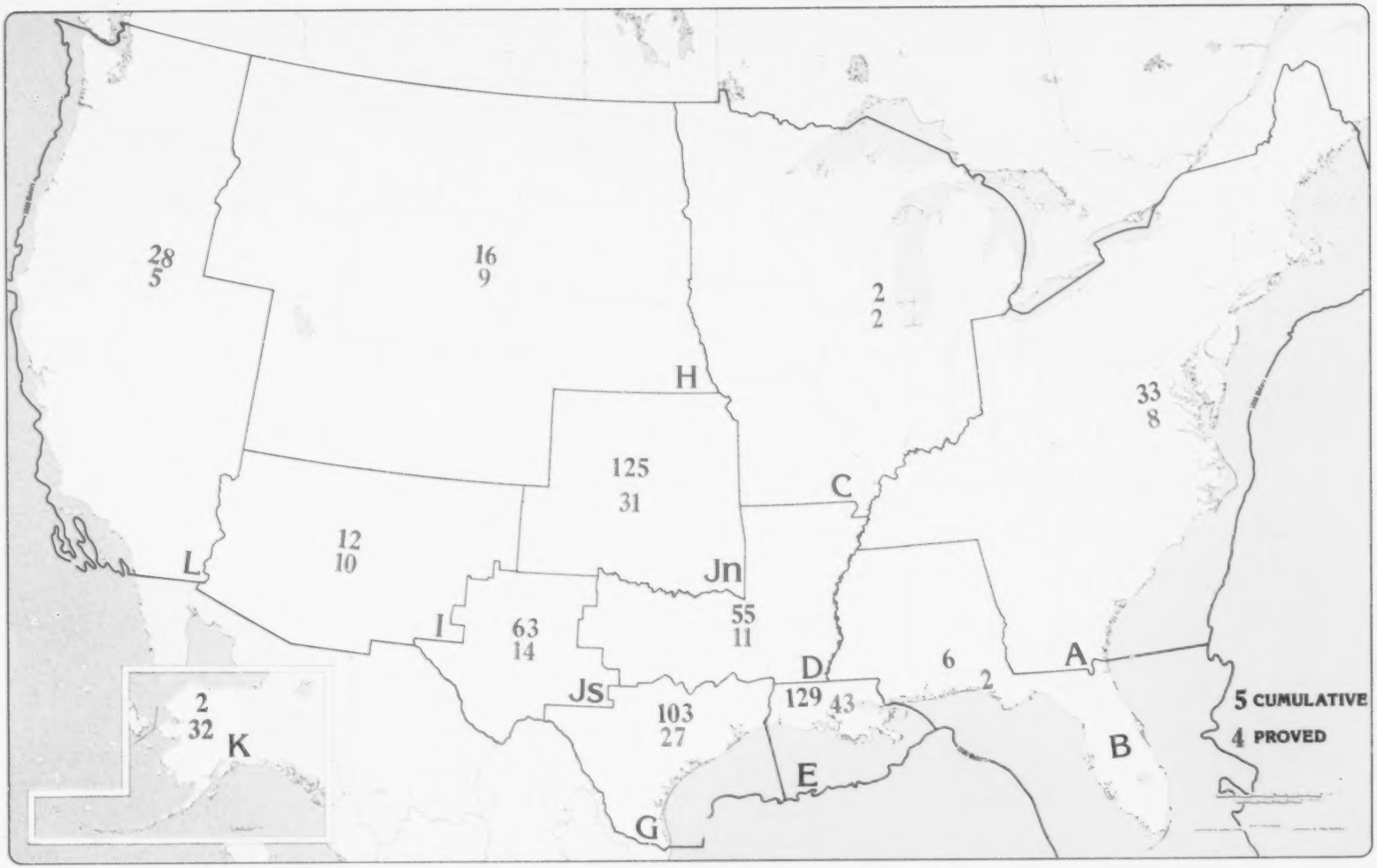

Figure 19—Geographic distribution of cumulative natural gas production and proved natural gas reserves as of December 31, 1979

of U.S. proved reserves of crude oil and natural gas based on data submitted to the Department by selected oil and gas well operators as of December 31, 1977. A second report in this series, reporting estimates of proved reserves of crude oil and natural gas as of December 31, 1978, was issued in September 1980. This series of reports by the Department of Energy is intended to replace the reports of the American Gas Association and the American Petroleum Institute.

All subsequent comparisons between the PGC's estimate of potential supply as of December 31, 1980 and the cumulative production and proved reserves data as of December 31, 1979 must be made with difference in reporting dates in mind. Based upon historical trends, it may be assumed that cumulative production figures for 1980 will be approximately 19 Tcf greater than those for 1979 presented here, while proved reserves will possibly decline relative to the 1979 estimates.

Estimates of ultimately recoverable volume, including the future potential estimated by the Potential Gas Committee plus past production and present proved reserves, have remained consistent considering the modifications to limiting parameters which have been made throughout the years. (See table 21.) The consistent total of ultimately recoverable volume reflects the fact that quantities of natural gas have been developed regularly from potential supply through exploration and drilling into proved reserves and ultimately into production. (Table 22 summarizes the ultimately recoverable volumes of natural gas in the United States by PGC reporting areas.)

The estimate of ultimately recoverable volume for the total United States, as of year-end 1980, is lower than the estimate for year-end 1978. This lower estimate reflects the net result of (1) transfers of volumes of natural gas from potential supply to proved reserves and production and (2) increases and decreases in estimates due to re-evaluation of the potential based on newly available geological, geophysical and engineering data. About one-third of the nationwide decrease in estimated potential is probably the result of transfers from potential supply to reserves and production. The areas of major decreases due to re-evaluation of estimates of natural gas potential are the U.S. Atlantic offshore region, especially the area of the Baltimore Canyon (Area A), south Louisiana onshore and offshore, except the deep Tuscaloosa trend (Area E), the Texas Gulf Coast and south Texas onshore and offshore (Area G) and Alaska (Area K). The areas of major increases in estimates of potential resources are the Eastern Overthrust Belt (Area A), the deep Tuscaloosa trend (Area E), and the Green River, Uinta, Piceance and Wind River basins, and Montana (Area H). More details of these re-evaluations are given in the various area reports.

In the past two years, the level of exploratory drilling activity in the United States has continued a pattern of significant annual increases which has prevailed for the past few years. Table 23 summarizes the number and footage of exploratory wells drilled for each of the years from 1972 through 1980. Estimates for the total number of exploratory wells drilled in the United States indicate that approximately 1,400 more exploratory wells were drilled in 1980 than were drilled in 1979 and approximately 1,200 more in 1980 than in 1978. The average depth of exploratory wells decreased from 5,923 feet in 1978 and 5,958 feet in 1979 to 5,870 feet in 1980. The increase in exploratory drilling activity can certainly be correlated to increased emphasis on natural gas and oil exploration coupled with the changes in regulatory climate and the improved economic situation. The exploration industry seems to be responding well to the initiation of phased deregulation of gas prices, to price incentives for certain types of gas, and to increases in the price of oil.

The year 1973 marked a low point in the level of exploratory drilling activity in the total country. Since then, exploratory drilling has increased almost annually both in the number of wells drilled and in the total footage drilled. Overall, the number of exploratory wells drilled has increased in 1980 by 77% over the number of wells drilled in 1973. The average well depth was shallowest in 1976 (5,719 feet) and increased to a record level of over 5,900 feet in 1978 and 1979 and dropped again in 1980 to slightly less than 5,900 feet (table 23).

Although there were significant nationwide increases in exploratory drilling activity, the increases were not uniformally spread across the total United States (table 24). All of the Potential Gas Committee areas, except Areas E, G and J-North, experienced an increase in the total number of exploratory wells drilled and in the total exploratory footage drilled in 1980 compared to 1978. Areas E and G showed a decrease in both categories. Area J-North showed a decrease in number of wells drilled but an increase in footage drilled. On a percentage basis, Area I experienced the greatest percentage increase in the number of exploratory wells drilled. In terms of increase in the absolute number of exploratory wells drilled, Area D had the greatest increase.

Total drilling activity (table 25), including both development and exploratory wells, has increased even more sharply since 1973 than the number of exploratory wells. In 1973, 26,592 total wells were drilled in the United States. Data for 1980 indicate that 62,462 wells were drilled, representing a total drilled footage of almost 289 million feet. The 1980 number of wells is a 135% increase over the number drilled in 1973. All of the drilling statistics indicate a strong and active effort to develop those resources which have already been discovered and to search for new gas and oil resources.

Table 21 — Comparison of estimates of ultimately recoverable volumes of natural gas in United States for period December 31, 1966 to December 31, 1980 (trillions of cubic feet at 14.73 psia and 60° F.)

	(a)	(b)	(c)	(d)	(e)
	PREVIOUSLY DISCOVERED				
	Cumulative Production*** (excluding gas currently in underground storage)	Proved Reserves (including gas currently in underground storage)	Production plus Reserves (a + b)	POTENTIAL SUPPLY (total of Probable, Possible and Speculative categories)	ESTIMATE OF ULTIMATELY RECOVERABLE VOLUME (c + d)
Lower 48 States					
As of 12-31-66	307	286	593	690	1,283
As of 12-31-68	344	282	626	800	1,426
As of 12-31-70	387	260	647	851	1,498
As of 12-31-72	431	235	666	780	1,446
As of 12-31-76	514	184	698	698 to 748	1,396 to 1,446
As of 12-31-78	551	169	720	830	1,550
As of 12-31-80	571*	163*	734*	768	1,502
Total United States**					
As of 12-31-68	345	287	632	1,227	1,859
As of 12-31-70	387	291	678	1,178	1,856
As of 12-31-72	432	266	698	1,146	1,844
As of 12-31-76	515	216	731	923 to 973	1,654 to 1,704
As of 12-31-78	553	200	753	1,019	1,772
As of 12-31-80	573*	195*	768*	913	1,681

*Cumulative production and proved reserves estimates are year-end 1979 estimates of the A.G.A. Committee on Natural Gas Reserves; 1980 data not available at the time of compilation.
**Alaska not estimated as of 12-31-66.
***Cumulative production adjusted to reflect most current available estimates.

Table 22 — Summary of ultimately recoverable volumes of natural gas in the United States by geographic areas as of December 31, 1980* (trillions of cubic feet at 14.73 psia and 60° F.)

	(a)	(b)	(c)	(d)			(e)
	PREVIOUSLY DISCOVERED — 1979						
Area	Cumulative Production*** (excluding gas currently in underground storage)	Proved Reserves (including gas currently in underground storage)	Production plus Reserves (a + b)	POTENTIAL SUPPLY — 1980			ESTIMATE OF ULTIMATELY RECOVERABLE VOLUME (c + d)
				Probable	Possible	Speculative	
A	33	8	41	26	9	51	127
B	6	2	8	6	7	41	62
C	2	2	4		2	1	7
D	55	11	66	9	22	20	117
E	129	43	172	25	56		253
G	103	27	130	30	35	4	199
H	16	9	25	40	78	69	212
I	12	10	22	2	3	1	28
J-North	125	31	156	27	66	42	291
J-South	63	14	77	16	34	1	128
L	28	5	33	4	17	24	78
Lower 48 States Subtotal	571**	163**	734**	185	329	254	1,502**
K-Alaska	2	32	34	8	29	108	179
Total United States	573**	195**	768**	193	358	362	1,681**

*Cumulative production and proved reserves estimates are year-end 1979 estimates of the A.G.A. Committee on Natural Gas Reserves; 1980 data not available at the time of compilation.
**Area estimates do not add to national totals because of rounding.
***Cumulative production adjusted to reflect most current available estimates.

Table 23 — Exploratory wells — total United States
(data from API Quarterly Review of Drilling Statistics)

	Number of Exploratory Wells Drilled	Footage	Average Well Depth
1972	7,539	45,043,798	5,975
1973	7,466	44,776,906	5,997
1974	8,619	50,261,744	5,832
1975	9,214	53,846,303	5,844
1976	9,234	52,812,406	5,719
1977	9,961	57,654,874	5,788
1978	10,677	63,234,745	5,923
1979	10,484	62,467,188	5,958
1980	11,916	69,948,320	5,870

Table 24 — Number of exploratory wells drilled, footage drilled, and average depth of wells — 1978 and 1980
(data from API Quarterly review of Drilling Statistics)

Area	1978			1980		
	No. of Wells	Footage	Average Well Depth	No. of Wells	Footage	Average Well Depth
A	862	2,189,177	2,540	963	2,477,501	2,573
B	326	2,873,439	8,814	365	3,191,595	8,744
C	805	2,549,094	3,166	1,104	3,332,148	3,018
D	1,578	7,898,646	5,005	2,060	10,517,328	5,106
E	520	6,374,356	12,258	465	5,863,586	12,610
G	1,870	13,374,429	7,152	1,744	13,019,459	7,465
H	1,734	10,988,116	6,336	1,922	12,340,162	6,420
I	45	171,021	3,800	89	300,816	3,380
J-N	1,673	8,300,895	4,962	1,654	8,539,880	5,163
J-S	861	5,945,680	6,906	1,072	7,282,727	6,794
K	13	128,542	9,888	18	190,543	10,586
L	383	2,362,126	6,167	444	2,723,247	6,133
Total U.S.*	10,677	63,234,745	5,923	11,916	69,948,320	5,870

*Includes Gulf of Mexico-Northern

Table 25 — Drilling activity summary 1973-1980
(data from API Quarterly Review of Drilling Statistics)

	Exploratory Wells		Total Wells	
	Number	Million Feet	Number	Million Feet
1973	7,466	44.8	26,592	136.4
1974	8,619	50.3	31,698	150.6
	15% increase over 1973		19% increase over 1973	
1975	9,214	53.8	37,235	174.4
	7% increase over 1974		17% increase over 1974	
	23% increase over 1973		40% increase over 1973	
1976	9,234	52.8	39,765	181.8
	1% increase over 1975		7% increase over 1975	
	24% increase over 1973		50% increase over 1973	
1977	9,961	57.7	46,479	215.0
	8% increase over 1976		17% increase over 1976	
	33% increase over 1973		75% increase over 1973	
1978	10,677	63.2	48,513	231.4
	7% increase over 1977		4% increase over 1977	
	43% increase over 1973		82% increase over 1973	
1979	10,484	62.5	51,263	243.2
	2% decrease over 1978		6% increase over 1978	
	40% increase over 1973		93% increase over 1973	
1980	11,916	69.9	62,462	288.9
	14% increase over 1979		22% increase over 1979	
	60% increase over 1973		135% increase over 1973	

Potential Gas Resources From Nonconventional Sources[1]

Potential Gas Agency, Golden, Colorado

INTRODUCTION

A large potential natural gas resource exists in the United States within reservoirs that are not producible with the conventional drilling and production techniques employed in the past. This section, prepared by the Potential Gas Agency, is a review of the status of research and knowledge regarding the potential production of natural gas from nonconventional sources and includes published estimates of the magnitude of this potential supply. This section was first included in the Potential Gas Committee's 1979 report, and reviewed the potential natural gas supply from geopressured-geothermal zones, gaseous coal seams, tight (low permeability) formations, and brown (Devonian) shales. The present review updates the earlier one with the developments which have come to our attention during the past two years in each of these categories. In addition, the review has been expanded to include a fifth category of nonconventional natural gas resource, namely, gas hydrates.

It must be emphasized that this review is not an independent appraisal by either the Potential Gas Committee or by the Potential Gas Agency of the volume of natural gas within nonconventional sources, but only a summary of published reports made by other agencies on this subject. The estimates contained in this section must not be confused with those prepared by the Potential Gas Committee. It is important, however, to understand the relationship between the estimates of potential supply from nonconventional sources and those reported by the Committee.

The estimates of potential supply of natural gas in the United States prepared by the Potential Gas Committee include only those quantities of natural gas which meet the specific guidelines established by the Committee; that is, only natural gas considered by the Committee to be recoverable in the future under assumed conditions of adequate economic incentives in terms of price-cost relationships and current or foreseeable technology is included in those estimates. In the past, the feasibility of recovering natural gas from nonconventional sources had not been reasonably demonstrated. Consequently, natural gas from such sources has largely been excluded from the Committee's estimates. In recent years, however, interest in the potential supply of natural gas from nonconventional sources has increased as well as the availability of information about them. Improvements in drilling and production technology accompanied by a more favorable economic climate have made it possible for future recovery of significant volumes of natural gas from some of these sources. As a result of these developments, the Committee has included in its current estimates some quantities of natural gas from sources that were previously considered to be nonconventional.

Natural gas recovery from geopressured-geothermal zones of the U.S. Gulf Coast region, coal seams, and gas hydrates has not yet been adequately demonstrated, and no potential supply from these sources is included in the estimates presented by the Committee. The potential natural gas resource from the brown

[1] This report is a revision and expansion of the report on potential gas resources from nonconventional sources prepared by Wilson H. Herrod and published in *Potential Supply of Natural Gas in the United States (as of December 31, 1978)*. The sections dealing with natural gas from geopressured aquifers, tight formations, Devonian shales and gas from coal seams were revised by James C. Donaldson, Potential Gas Agency and Department of Geology, Colorado School of Mines. The section on gas hydrates was written by James J. Emme, Department of Geology, Colorado School of Mines.

We are grateful for the contributions made by John F. Bergquist, Myron H. Dorfman, Alex Gillies, Malcolm A. Goodman, Richard D. McIver, John L. Moore, William F. Morse, Harvey S. Price, A. D. Rial, and John C. Sharer by their review of various sections of this report.

(Devonian) shales of the Appalachian, Illinois, and Michigan basins is largely excluded except for that portion which exists in areas geologically similar to regions currently producing gas from brown shales and is believed to be recoverable by conventional drilling and improved well stimulation and completion methods. Potential supply of natural gas from tight formations (including sandstone, shale, and carbonate reservoirs) is included in the Committee's estimates in areas where this resource is considered to be within the guidelines established by the Committee. In some cases, this will include gas from formations with less than one millidarcy permeability. The estimates for gas resources from tight formations prepared by other estimators and presented in this section are generally based upon evaluation of formations with less than one millidarcy permeability; consequently, these estimates may somewhat overlap those prepared by the Committee. Because of changing definitions and differences in estimation methods of gas from tight formations, there is no clear boundary between the Committee's estimates and those reported by others. The possible overlap and the uncertainty in the boundary will require further investigation.

NATURAL GAS FROM GEOPRESSURED AQUIFERS

The term *geopressure* was introduced during the 1950s by petroleum engineers to describe subsurface intervals where the pressures encountered exceeded those anticipated for a particular depth. A geopressured zone, or synonymously, an "overpressured" or "abnormally pressured" zone, is one in which fluid pressures are greater than the normal, or hydrostatic, pressure because at least part of the rock overburden load is being supported by the fluid. Under hydrostatic conditions, the fluid pressure for any subsurface point may be approximated by applying a gradient of 0.465 psi per foot of depth, which is roughly equivalent to the weight of a column of normal marine water of the same height. However, with geopressured zones the pressure gradient may be as great as 0.98 psi foot, largely reflecting the weight of the overlying sedimentary rocks (Dorfman, 1976, p. 34). Geopressured zones have been found in various regions of the United States (fig. 20). However, since the largest and most likely commercial targets are located in the Gulf Coast region, most research and interest has been restricted to this area. Consequently, this review is confined to summarizing findings for the Gulf Coast region only.

In general, geopressured zones arise from the compaction of rapidly deposited clays and sands of low overall permeability. Such conditions are commonly associated with deltaic sedimentation such as characterizes the northern Gulf of Mexico, or Gulf Coast, basin. As shown in figure 21, Cenozoic sediments associated with major centers of deltaic deposition along the Gulf Coast attain thicknesses of 50,000 feet (15,250 m). These sediments are largely composed of sands, silts and clays deposited by delta systems ranging in age from Eocene to Holocene. The overall pattern is one of sediment-induced regression of the sea with a consequent gulfward shift of successive depositional sites. As a result of this leapfrogging of sediment wedges, large volumes of sands and clays were quickly deposited atop soft, unconsolidated muds and silts. This rapid loading resulted in clay compaction and the isolation of porous and permeable sands within impermeable shales. In addition, large, generally southward-dipping, growth faults developed which further compartmentalized these sands (fig. 22). The isolated, their interstitial fluids were forced to accommodate at least part of the subsequently deposited sediment load, and thereby became geopressured. The ultimate pressure which can be achieved under such conditions is directly proportional to the rate of loading and indirectly proportional to the mean transmissibility of the enclosing rocks. Within the Gulf Coast geopressured intervals, pressure gradients often approach lithostatic pressures, or 1.0 psi foot, and actual pressures may exceed 16,000 psi at drilled depths (Jones, 1977, p. 903).

Besides abnormally high pressures, geopressured zones are also characterized by elevated geothermal temperature gradients (fig. 23). Since heat flow is primarily a function of convective groundwater movement, the hydrostatic conditions near the top of the geopressured zone act as a thermal blanket. Therefore, in going from the hydrostatic to the geopressured zone of the Gulf Coast, a sharp increase in the geothermal gradient is experienced. Temperatures within the geopressured zone generally vary from about 300° F. to 500° F. (149° C. to 260° C.), and temperatures within potential sand reservoirs range from 300° F. to 350° F. (149° C. to 177° C.) (Dorfman, 1976, p. 34). Others would extend the lower limit of the temperature range to 200° F. (93° C.) (J. C. Sharer, private communication, 1981; Jones, 1977). In a recent evaluation of two wells in Texas and Louisiana, the National Petroleum Council (1980) reports generally higher temperatures in the Texas geopressured zones. Temperatures for the Texas sediment were on the order of 300° F. (149° C.) compared to a range of 230° F. to 320° F. (108° C. to 160° C.) for the Louisiana sediment.

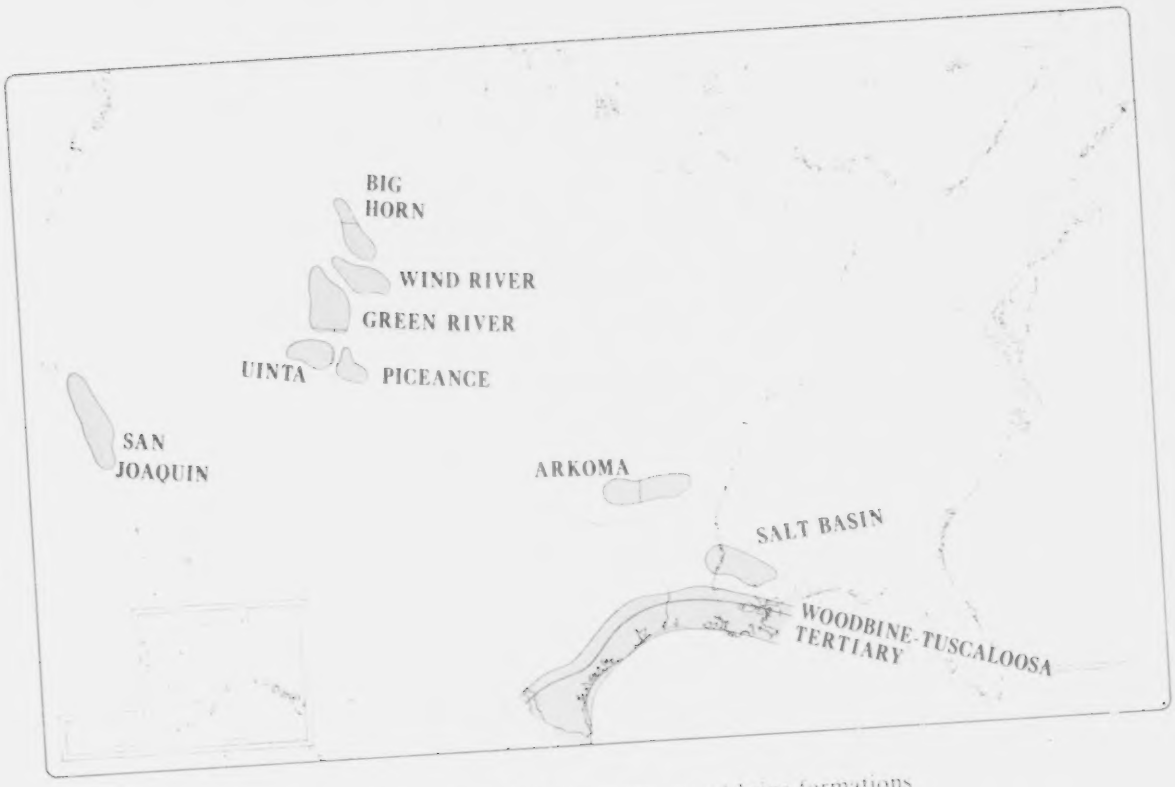

Figure 20 — United States geopressured brine formations

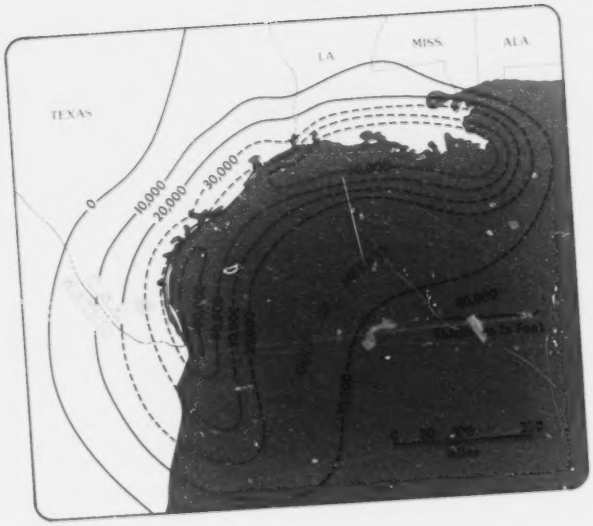

Figure 21 — Thickness of Cenozoic deposits in the Gulf Coast basin (After Dorfman, 1977) Reproduced courtesy of Dr. M. H. Dorfman

Another anticipated characteristic of geopressured zones, based on early work, was reduced water salinity (fig. 24). Water salinities within the geopressured zones were originally expected to be less than 20,000 ppm in contrast to those within the overlying hydropressured intervals frequently exceeding 100,000 ppm (Dorfman, 1977, p. 880). However, recent testing of geopressured zones has shown salinities as high as 150,000 ppm and an expected range for most prospects on the order of 40,000 to 80,000 ppm (J. C. Sharer, private communication, 1981). A reduction in salinity is probably caused in part by the expulsion and hyperfiltration of bound water from adjacent shales, due to the thermal transformation of montmorillonitic clay into mixed-layer clay in the geopressured environment (Dorfman, 1976, p. 35; 1977, p. 880). This expulsion may serve to transport generated hydrocarbons from source rock to reservoir as well as to replace saline water with brackish water within sandstones.

Within the Gulf Coast basin, the top of the geopressured zone can be detected and mapped using drilling, seismic, or well log data. Figure 25 illustrates five pressure-prediction parameters for a Louisiana Gulf

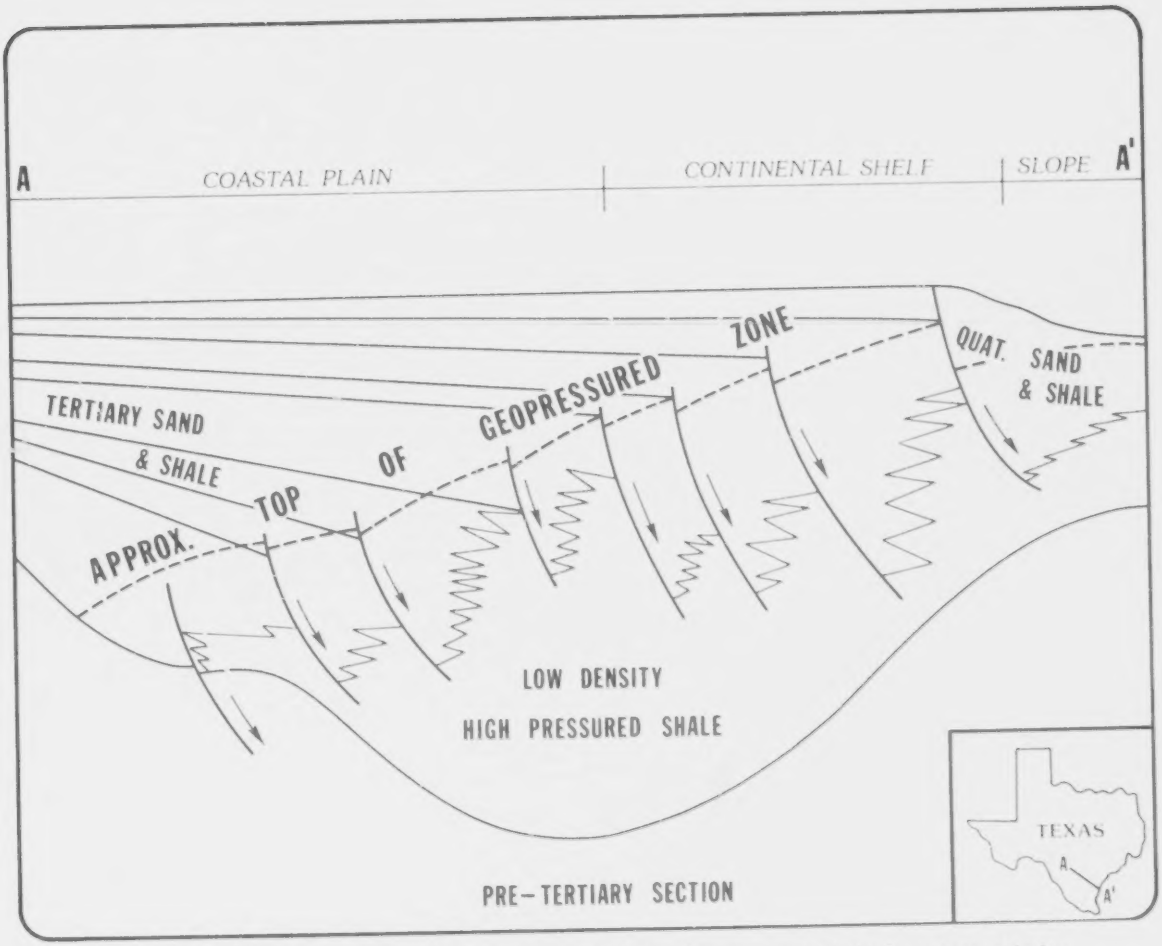

Figure 22 Section across South Texas Coastal Plain, showing growth-fault systems relative to the top of the geopressured zone (After Dorfman, 1977)
Reproduced courtesy of Dr. M. H. Dorfman

Coast well. Dorfman (1980) has recently stressed the fact that these parameters may change for different areas of the Gulf Coast. His research in the Armstrong and Corpus Christi fairways showed that, contrary to earlier published data (Hottman and Johnson, 1965), the decrease in shale resistivity did not correspond to the top of the geopressured zone, but occurred at a pressure gradient of about 0.7 psi/foot. Jones (1977, p. 890) has noted that the depth to the top of the zone varies from less than 3,000 to about 18,000 feet (915 to 5,490 m) (fig. 26). Although the 200° F. (93° C.) isotherm is commonly near the top of the geopressured zone, no clear relationship between temperature and pressure exists. As much as 5,000 feet (1.6 km) of relief may be exhibited by the 200° F. (93° C.) isotherm within a 100-square-mile area.

Interest in geopressured aquifers increased with the idea that it might be possible to harness the heat of the fluids contained in these zones and convert it into electrical energy. Additional attention to geopressured zones has been aroused by the possibility of obtaining hydraulic energy and now, more importantly, natural gas.

Methane is contained within geopressured zones in three forms: (1) gas in solution, (2) free gas, and (3) residual gas (Sharer, 1980). Published estimates of the amount of gas in geopressured brines include only the gas in solution, and not the possible contribution of free and residual gas to production. In general, the solubility of methane in water is directly proportional to reservoir temperature and pressure, and inversely proportional to formation-water salinity. Figure 27 illustrates the relationships between methane solubility as a function of pressure for specific values of

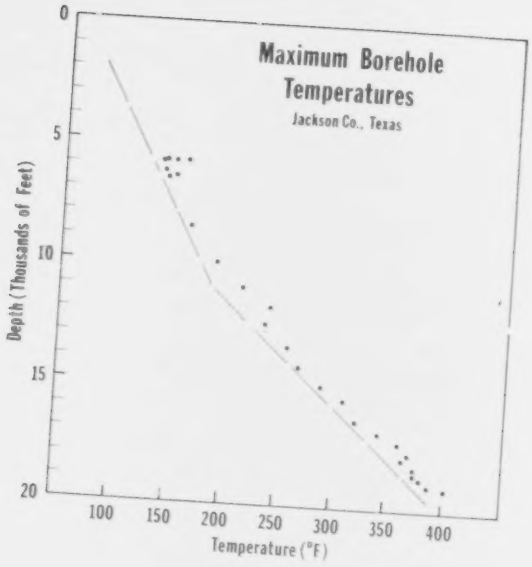

Figure 23 — Relationship between average geothermal gradient and occurrence of geopressure in the central Texas Gulf Coast (After Jones, 1977)
Reproduced courtesy of Dr. P. H. Jones

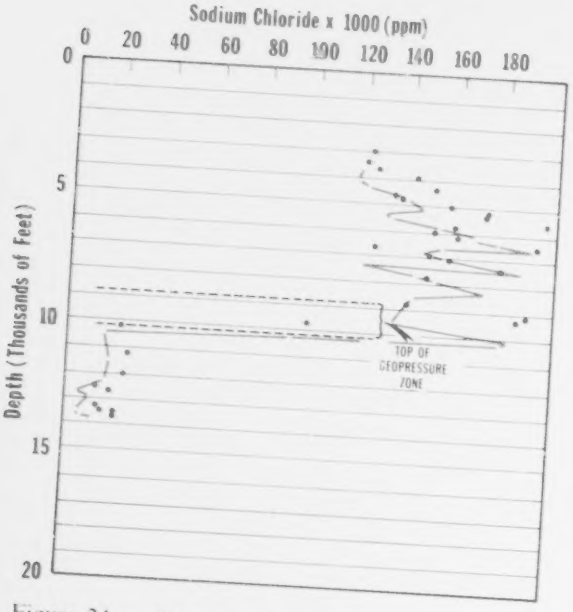

Figure 24 — Change in formation water salinity with depth relative to the top of the geopressured zone, Manchester Field, Louisiana (After Bebout, et al., 1978)
Reproduced from the Bulletin of the American Association of Petroleum Geologists by permission

temperature and salinity (assuming full saturation). Variations in temperature, pressure and water salinity make prediction of gas saturation difficult. Typical saturation levels of geopressured brines are between 20 to 40 standard cubic feet of gas (scf) per barrel (bbl) of brine. Produced-gas-to-water ratios with values of up to 70 scf/bbl have been reported where co-production of residual gas and/or free gas was anticipated (J. C. Sharer, private communication, 1980).

The Resource

A number of estimates of the dissolved methane resource within the Gulf Coast geopressured aquifers have been made and are summarized in table 26. The most recent estimate, published in 1979 by the U.S. Geological Survey, reported a total in-place resource in both offshore and onshore areas of 5,700 Tcf (Wallace, et al., 1979). In the most conservative scenerio used in the study, the ultimately recoverable resource was estimated to be 150 Tcf. Lewin and Associates (1978) estimated a total in-place onshore resource of 860 Tcf with 42 Tcf of this considered to be recoverable. After re-evaluation of the Texas portion (Oligocene Frio Formation only), the estimate of Lewin and Associates was revised upward the following year to 1,100 Tcf and 50 Tcf for in-place gas resource and recoverable resource, respectively (cited in Kuuskraa and Meyer, 1980). This latter estimate compares well with Bernard (1978), who concluded that the recoverable resource for the Gulf Coast is 54 Tcf. Jones (1976 and 1977) is, by far, the most optimistic of all evaluators and has estimated a total resource in-place, in geopressured brines, both onshore and offshore, of 49,000 Tcf. He also speculated that a comparable volume could be present

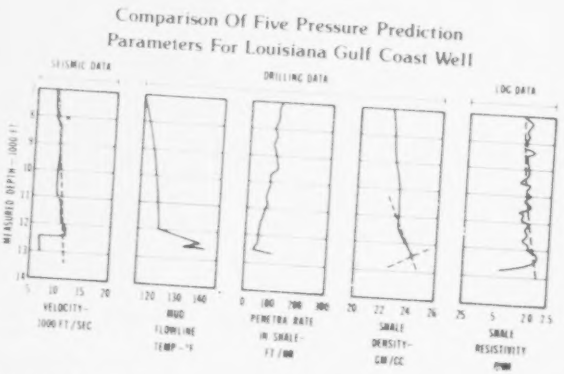
Comparison Of Five Pressure Prediction Parameters For Louisiana Gulf Coast Well
SEISMIC DATA
DRILLING DATA
LOG DATA
MEASURED DEPTH - 1000 FT
VELOCITY - 1000 FT/SEC
MUD FLOWLINE TEMP - °F
PENETRA RATE IN SHALE - FT/HR
SHALE DENSITY - GM/CC
SHALE RESISTIVITY

Figure 25 — Geopressure prediction parameters for a Louisiana Gulf Coast well (After Jones, 1977)
Reproduced courtesy of Dr. P. H. Jones

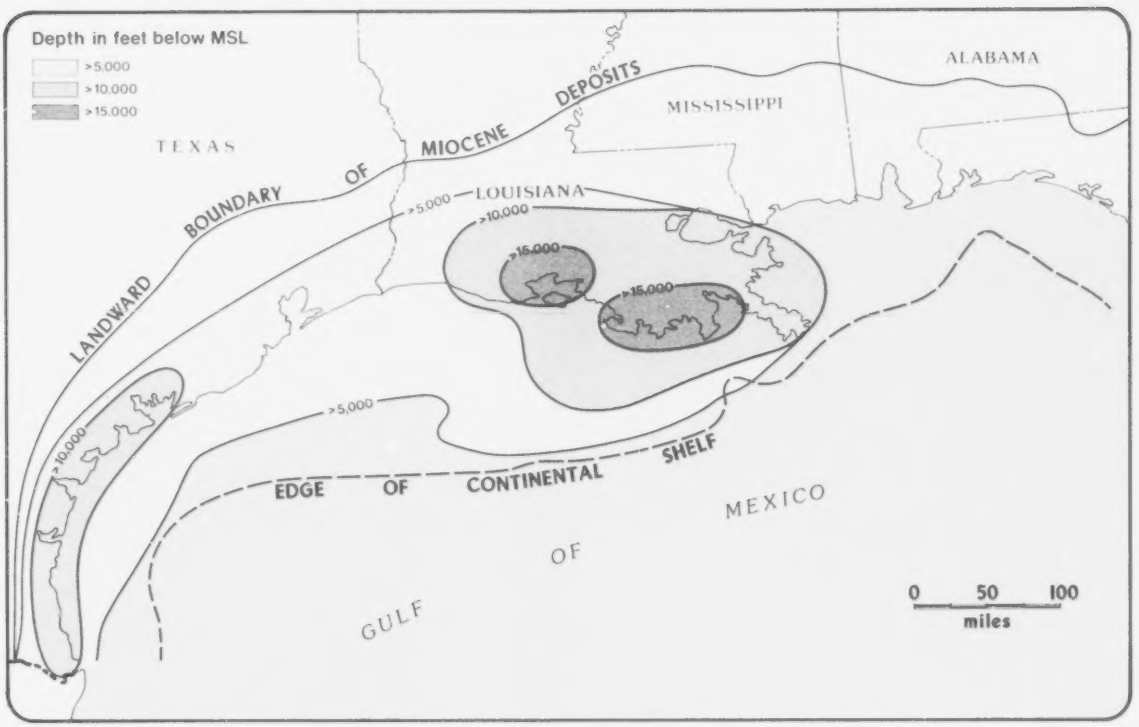

Figure 26 Depth of occurrence of geopressured zones (After Jones, 1977)
Reproduced courtesy of Dr. P. H. Jones

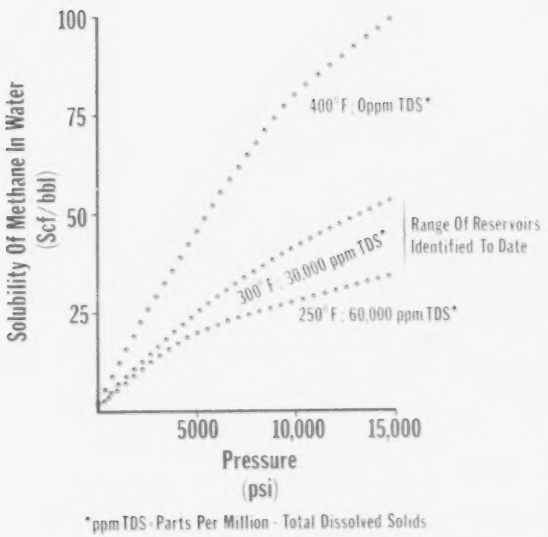

Figure 27 — Gas solubility in brine
(Kuuskraa and Meyer, 1980)

within associated geopressured shales, some of which might migrate into adjacent sands as the sands are depleted by production. Dorfman (1977) proposed an in-place resource of 5,735 Tcf for the same area and indicated that the recoverable resource is approximately 256 Tcf. This latter figure was presented as an idealized upper limit, based upon optimum geological conditions and without regard to time, rate of production, or economics. Hise (1976) estimated an in-place resource of about 3,000 Tcf, with 125 Tcf being physically recoverable, again, under optimum conditions. Papadopulos, et al. (1975) estimated 23,618 Tcf for the total gas in-place, with the ultimately recoverable resource ranging from 110 to 770 Tcf.

The wide variation in the resource estimates reflects both the many physical and economic uncertainties involved and the differing assumptions and approaches used by the various estimators. Two general areas where uncertainties arise are in the determination of: (1) the number and quality of geopressured reservoirs available, and (2) the volume of methane which may be dissolved in water under varying physical conditions.

Table 26 — Comparison of estimates of gas in geopressured aquifers (Tcf)

Source	Total Gas In-Place	Ultimately Recoverable Gas
Wallace, et al. (1979)		
Onshore	3,100	97
Offshore	2,800	53
Total	5,700	150
Lewin and Associates (1979)*	1,100	50
Lewin and Associates (1978)	860	42
Bernard (1978)		54
Dorfman (1977)	5,735	256
Jones (1976 and 1977)	49,000**	260-1,200***
Hise (1976)	3,000	125
Papadopulos, et al. (1975)	23,618	110-770***

*1979 revision cited in Kaiuskraa and Meyer, 1980.

**Jones speculated that another 45,000 Tcf may be present within associated geopressured shales, some of which might migrate into adjacent sands as they are produced.

***Cited in Sharer, 1980.

While the various estimators agree on the general area underlain by potential geopressured aquifers (which runs from the Rio Grande River to the Florida Panhandle, and from the landward limit of Eocene growth faulting, about 100 miles inland, southward to the edge of the continental shelf), they are not unanimous as to the number of square miles encompassed by this area. The Wallace, et al. (1979) study for the U.S.G.S. included 119,692 square miles (310,000 km^2), more than double the 55,985 square miles (145,000 km^2) used in the earlier Papadopulos, et al. (1975) study. Lewin and Associates (1978) used the same area reported in the U.S.G.S. 1975 evaluation. Jones (1976, p. 19) cites a figure of 150,000 square miles (388,500 km^2) while Dorfman (1977, p. 881) prefers 100,260 square miles (259,673 km^2), and Hise (1976, p. 57) uses an even 100,000 square miles (259,000 km^2).

For purposes of methane resource evaluation, both Jones (1976 and 1977) and Dorfman (1977) agree on a geopressure basement of 25,000 feet (7,625 m). Sediments below this depth consist largely of silts and shales with minimal reservoir potential. Furthermore, 25,000 feet appears to be a reasonable economic and technological limit for drilling. However, these two authors arrive at different conclusions relative to the total volume of geopressured sandstone within this interval and regarding the reservoir characteristics.

In contrast to the work of Jones and Dorfman, the Papadopulos, et al. (1975) study for the U.S.G.S. used a maximum depth of 19,685 feet (6 km) in Texas and 22,966 feet (7 km) in Louisiana. In the later U.S.G.S. study (Wallace, et al., 1979), they used a uniform depth of 22,500 feet (6.86 km). Lewin and Associates (1978) evaluated only the interval between 10,500 and 19,000 feet (3,209 m and 5,791 m, respectively).

While both Dorfman (1977, p. 881) and Hise (1976, p. 57) use 10,000 feet (3,050 m) for the average thickness of geopressured sediments throughout the basin, Dorfman considers 15 percent of this section to be actual reservoir sandstone with an average porosity of 22 percent, and Hise estimates that only 10 percent is composed of sandstone, with a slightly lower porosity of 20 percent. Rather than using an average reservoir thickness for the entire basin, Jones (1976 and 1977) bases his calculations on estimated cumulative reservoir sand (derived from regional facies studies and selected dip sections) within a representative subarea which is then extrapolated, with some adjustments, to the entire region.

General observations indicate that there are tendencies, perhaps inherent in any extrapolation, for estimators to assume more reservoir uniformity and continuity than may actually exist. It is known that the

principal geopressured reservoirs along the Gulf Coast are long, linear, often discontinuous, aquifers arranged in fairways which are parallel to the coast. Of five such fairways delineated with the Oligocene Frio Formation along the Texas coast, all save one exhibited either inadequate permeability or limited vertical or lateral reservoir development (Bebout, et al., 1978).

Variations in the estimates are also a reflection of differences in assumed values for methane solubility. The U.S.G.S. studies, Papadopulos, et al. (1975) and Wallace, et al. (1979), evaluated separate intervals and calculated methane content using temperature, pressure and salinity data from each one. Lewin and Associates used the same approach and obtained a methane content of 16 scf per barrel of brine at depths between 10,500 and 11,000 feet (3,200 m and 3,352 m) which increased to 47 scf per barrel for the interval 18,000 to 19,000 feet (5,486 m to 5,791 m). Dorfman (1977, p. 881) uses a value of 35 scf per barrel for calculating total resource in-place, and applies an average of 25 scf per barrel in determining recoverable volumes. Jones (1976 and 1977), on the other hand, uses a value which increases with depth from 18.8 scf per barrel at 8,000 feet (2,440 m) to 164 cu. ft. at 25,000 feet (7,625 m).

National Petroleum Council Study

A task force appointed by the National Petroleum Council (1980) recently evaluated the resource potential of geopressured aquifers. This study considered eleven prospective areas in Texas and Louisiana which had previously been selected as potential drill sites for geothermal energy and not for natural gas. From evaluation of these areas, projections were made for the development of undesignated areas which were modeled after one of the areas studied in detail. The amount of gas which could be recoverable by the year 2000 in the opinion of the task force was estimated for the eleven prospective areas and the projected, but undesignated, areas. This study assumed gas prices ranging from $4.00 to $9.00 per Mcf and a 10 percent (real) rate of return on investment. The different scenarios investigated by the task force involved different projections for the number of wells drilled and production rates. The most optimistic case resulted in a projected recovery of 568 Bcf from 96 wells by the year 2000, while the less optimistic case projected a recovery of 240 Bcf from 43 wells, also by the year 2000.

In evaluating the results of the NPC study, it is important to note that this study was restricted to a limited number of prospects originally selected for their geothermal potential and projection of these areas into a limited number of undesignated areas. The projections included an assumed rate of development to the year 2000. Additionally, the reservoir study was based upon models used for petroleum reservoirs which may not be applicable to aquifers with different major drives, including compaction of sediments and influx of water from adjacent shales (M. H. Dorfman and H. B. Harkins, private communication, 1981).

Current Research and Development

From the above discussion, it is clear that a considerable, though unknown, volume of natural gas might be recovered from the geopressured-geothermal aquifers of the Gulf Coast. The critical question then becomes, can this resource be produced economically? Recent research and development has largely been directed toward resolving this overriding uncertainty. To do so, additional data must be acquired in order to more thoroughly understand the following uncertainties:

- reservoir extent and continuity
- reservoir quality (porosity, permeability, thickness)
- gas recovery efficiency
- nature and saturation of the gas
- production problems (sand production, corrosion and scaling)

In 1975 the Petroleum Engineering Department of Louisiana State University, under contract to the Energy Research and Development Administration (ERDA, now part of the Department of Energy), began investigating the geothermal-geopressured resource of southern Louisiana for the purpose of locating promising prospects. More recently, the University of Texas at Austin completed a detailed geological and engineering analysis of the Oligocene Frio Formation of the Texas Gulf Coast, also with the purpose of delineating geothermal-geopressured drilling prospects (Bebout, et al., 1978). Prospective areas were expected to meet the minimum requirements of a reservoir volume of 3 cubic miles with a permeability of at least 20 millidarcys and a fluid temperature of 300° F. (149° C.), or greater. The 300° F. (149° C.) specification was designed to accent geothermal, as opposed to natural gas, resources. When methane dissolved in the geopressured waters became recognized as a potential major energy resource, reservoir requirements changed. An ideal prospective reservoir became one with (1) a minimum gas saturation of 30 scf/bbl of brine, (2) an initial bottom-hole pressure exceeding 12,000 psi, (3) a volume of at least one cubic mile, and (4) a thick and very permeable sand (Kuuskraa and Meyer, 1980).

The U.S. Department of Energy (initially under ERDA, later DOE) began a large program in 1977 to assess the energy potential of the geopressured zones. Under this program, four wells have been completed and tested. The results of these tests have shown that the amount of gas in solution was much lower than anticipated (ranging from 20 to 25 scf bbl). Low gas content was attributed to high concentrations of dissolved solids (100,000 to 200,000 ppm) (Kuuskraa and Meyer, 1980). One of these wells, the Edna Delcambre No. 1 well located in southern coastal Louisiana, produced methane at a rate of 70 cu. ft. per barrel of water, or roughly three times the amount of gas believed to be dissolved in the brine. These findings indicate the presence of free gas in the reservoir and are interpreted by Rosenberg and Sharer (1980) to indicate that free gas occupied up to 6.5 percent of the reservoir pore space. The validity of this idea depends on whether sufficient gas is available within a given reservoir to both saturate the reservoir water and to partially fill available pore space as a separate phase. Continuation of the DOE test program may resolve the validity of this hypothesis which, if correct, will result in a geopressured natural gas resource that is much larger than current projections. At the present time, however, the anomolously high methane concentration observed in the brines produced from the Edna Delcambre No. 1 well is the exception to the rule and the free gas hypothesis remains speculative at best.

Obstacles to Commercialization

Perhaps the greatest obstacle to full commercialization of geopressured gas resides in our ignorance of the true nature and extent of the resource. Undoubtedly, the DOE evaluation program will alleviate some of this uncertainty. However, other technological, legal, economic and environmental problems exist.

Technological

While the technology to produce hot, geopressured brines exists, it has never been tested, certainly not at the high flow rates (in excess of 50,000 barrels of water a day) anticipated by many authors as economically necessary for an adequate rate of return on investment. The high flow rates combined with the poorly consolidated nature of some aquifer sandstones may generate problems with sand control. Production problems may also arise because of permeability reduction due to declining aquifer pressures (Lewin and Associates, 1978). DOE tests at the Fairfax Foster Sutter No. 2 well in Louisiana and the Pleasant Bayou No. 2 well at Austin Bayou in Texas have shown that dissolved carbon dioxide reduced the pH levels of the geopressured brines to 6 or below. Such acidity may cause serious down-hole corrosion which, with the high production rates, would be difficult to treat or prevent (National Petroleum Council, 1980).

Legal

Legal problems relate both to ownership and operating practices. Since the potential resource spans several states, each will have to establish guidelines, hopefully similar, for ownership of solution gas relative to previously established oil and gas leases. In addition, distinction between geopressured solution gas rights and water rights will be required. Due to the large reservoirs required to sustain the high productivity rates demanded by economics, a great number of land and royalty owners are likely to be involved in any one prospect.

Economic

Uncertainty exists regarding the economic viability of geopressured solution gas production. The economics are complicated by a fundamental lack of knowledge about the resource. It is not known whether or not sustained brine production rates are possible, and if so, for what length of time and at what flow rate. The problem is also compounded by the inability to predict methane content of the brines. In an attempt to quantify the uncertainties, scenarios have been developed to show the minimum production rates and methane content required to recover investment costs for assumed gas price levels (Lewin and Associates, 1978). In addition, estimates for ultimately recoverable gas have been calculated for assuming different production rates, methane content and gas-price levels (National Petroleum Council, 1980). Lewin and Associates (1978) estimated that at gas prices of $1.75, $3.00 and $4.50 per Mcf (1977 dollars) the amount of economically recoverable gas is reduced from the maximum 42 Tcf recoverable to about none, 1.1 Tcf and 5.4 Tcf, respectively. When one includes additional benefits from the produced fluids such as power generation, heating, or industrial applications, the economics may improve on a site-specific basis. At the same time, however, these additional uses impose limitations relative to minimum permissible reservoir temperature and pressure, and may limit the recovery of the resource base. The uncertainty related to the cost of disposal of produced brines further clouds the economic picture. However, if co-production of mobile and or immobile gas in conjunction with solution gas is plausible, economic recovery of methane could be attractive in the near future (Geer and Sharer, 1980).

Environmental

Several environmental problems are posed by producing huge volumes of geopressured-geothermal waters.

First, there is the problem of what to do with the water once the gaseous, mechanical and thermal energy has been depleted. Since salinity of the water precludes surface discharge (at least onshore), most plans call for reinjection into shallower sands. Second, there is the potential of subsidence. Hise (1976, p. 60) estimates a maximum subsidence of 1.0 m might occur directly above the center of a producing aquifer. However, Jones (1976, p. 69) has observed that since one-half to two-thirds of the resource occurs offshore, subsidence might not be as great a problem. Finally, there is the possibility that depressuring of deep reservoirs, which are often associated with growth-fault development, while at the same time pressuring shallower reservoirs by fluid injection could trigger recurrent movement along faults.

Conclusions

Geopressured aquifers in the Gulf Coast contain a large natural gas resource estimated to be between 1,100 (Lewin and Associates, revised estimate, 1979, cited in Kuuskraa and Meyer, 1980) and 49,000 Tcf (Jones, 1976, 1977) in-place. The estimated recoverable resource is between 50 (Lewin and Associates, revised estimate, 1979, cited in Kuuskraa and Meyer, 1980) and 1,200 Tcf (Jones, 1976 and 1977, cited in Sharer, 1980). Adequate technology for drilling geopressured reservoirs presently exists, but the technological, legal, economic and environmental uncertainties involved in recovery of this potential resource currently deter development efforts. Most authors doubt significant production prior to 1985 (Dorfman, 1977, p. 885), and the National Petroleum Council report (1980) concludes that "large-scale production is highly unlikely prior to the year 2000".

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GASEOUS COAL SEAMS

The occurrence of methane in coal has been the subject of investigation since the early part of this century. The purpose of past investigations was largely to improve mine safety by averting the accumulation and explosion of indigenous methane. Recently, the accepted practice has been to dilute the methane with air as it is piped to the surface from mine workings. Kuuskraa and Meyer (1980) estimate that approximately 217 MMcf per day, or 80 Bcf per year is lost to the atmosphere in this manner.

Methane is a by-product formed during the conversion of organic material to coal, a process referred to as coalification. Though much of this gas is lost to the atmosphere, a substantial portion is retained as (1) gas absorbed on the surface of the microporous structure of the coal, (2) free gas in vertical joints and fractures (cleats) in the coalbed, and as (3) desorbed gas trapped within adjacent sediments. Categories (1) and (2) represent a nonconventional gas resource which is directly determined by the nature of the producing interval, namely the coal seam. Category (3) represents a resource which is difficult to classify as a conventional or nonconventional resource. In situations where adjacent sediments are porous and permeable, trapped gas derived from coal seams can be produced by conventional drilling and completion procedures.

Because of the natural association of methane with coalbeds, the geological dimensions of the gas resource are defined by the extent of the subsurface coalbeds (fig. 28). The amount of gas to be found within a given coal unit is a function of, among other things, the rank of the coal and the depth of burial (fig. 29). The rank of coal is important since methane content is inversely proportional to the moisture of the coal. Moisture content decreases with an increase in coal rank resulting in a corresponding increase in methane content. The rank of a coal depends upon its degree of coalification which is a function of time, temperature and pressure. These factors are, in turn, determined by the tectonic and burial history of the organic material present. Depth of burial is important because it determines the pressure of the coal seam, and gas content increases with an increase in pressure.

The Resource

Estimates of total in-place gas resource vary between different studies and even show a wide range within studies (table 27). Variations are due, in part, to the limited data available for gas content of all coals and wide ranges in the estimates of the coal resource. In addition, researchers have made different assumptions and have used different approaches and methods in making their estimates.

The National Gas Survey Task Force on Nonconventional Natural Gas Resources has estimated that between 300 and 850 Tcf of methane may be present within the coalbeds of the United States (Federal Energy Regulatory Commission, 1978). This estimate is based on what is considered to be a conservative average of 200 cu. ft. of natural gas per ton of coal. Of the total of 850 Tcf, 300 Tcf is estimated to be associated with coal classified as "remaining identified resources," that is, with less than 3,000 ft. of overburden (excluding strippable zones). The remaining 550 Tcf is gas postulated to be associated with coals classified as "estimated hypothetical resources," that is, in unmapped and unexplored areas, and as "estimated additional hypothetical resources in deeper structural basins" (i.e., between 3,000 and 6,000 feet, or 915 to 1,830 meters in depth).

Deul and Kim (1978) estimate a total in-place resource of 766 Tcf of which 318 Tcf represents identified resources with the hypothetical resource being 448 Tcf.

The most recent estimates for total in-place gas resource are by the National Petroleum Council (1980) and Kuuskraa and Meyer (1980). Both of these studies used a similar approach which involved estimating the amount of coal resource by rank. Instead of assuming an average gas content per ton of coal, they used a different value for each rank of coal (based on moisture content). Kuuskraa and Meyer included one additional consideration and allowed for the effect of burial depth on gas content by using different yields for each rank for different depths (table 28). Even though the estimates for the total gas resource do show a large variation, they indicate a very large potential energy source to be obtained from gaseous coal seams. It must be mentioned, however, that estimates for the potential in-place resource do not account for the possibility that some portion of the initially-generated gas may have migrated to the ground surface, possibly through fissures in the coal deposit, and, consequently, have been lost to the atmosphere. If this has happened, the in-place resource would be less than the estimates indicate.

More important than the absolute value of in-place gas resource is the amount considered to be recoverable. Total gas in-place estimates are based on estimates of the total coal resource. Much of the coal resource, however, is found in beds considered to be too thin or of insufficient rank and depth to have gas production potential without major advances in production technology. Kuuskraa and Meyer estimate 550 Tcf for the total in-place gas resource, but by considering only

Figure 28 — Location of U.S. coal deposits
(After Deul and Kim, 1975)
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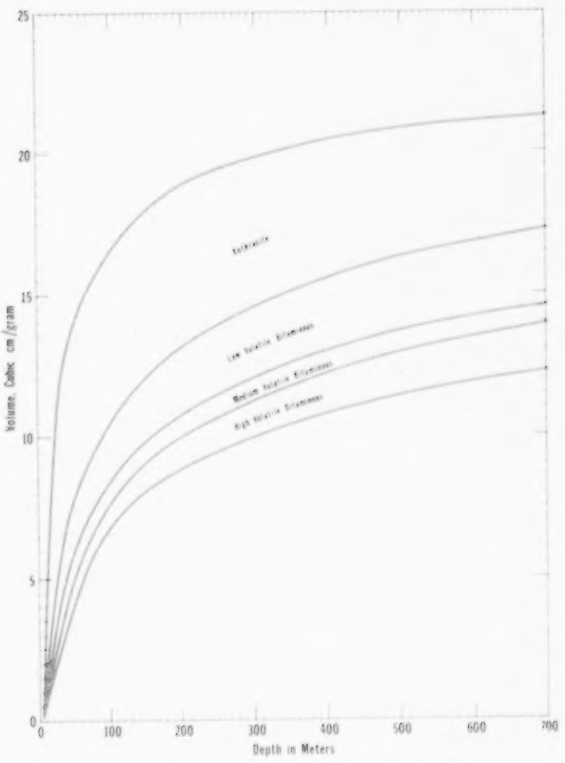

Figure 29 Estimated methane content of coal with depth and rank (Kim, 1977)

the coal resource with sufficient rank and depths and found in thick beds, they reduce this figure to 135 Tcf. One hundred thirty-five (135) Tcf is the favorable resource or what can reasonably be assumed to be a viable target for future production efforts. They estimate a 30-45% recovery efficiency which gives the amount of methane technically recoverable from coal seams to be in the range of 40-60 Tcf. In a 1979 review, Gas Research Institute summarized the estimates made by others of the recoverable resource as ranging from 16 to 487 Tcf (Rosenberg and Sharer, 1979). In a later paper based on their collection and interpretation of judgmental estimates of experts in the field, Gas Research Institute gave estimates of the amount of gas thought to be recoverable, at selected market prices of $3.00 to $6.00 Mcf (1979 dollars), of 10 to 30 Tcf for existing technology and 30 to 60 Tcf for advanced technology (Sharer, 1980).

Gas produced from coal seams is not pure methane, but its chemical composition is generally such that it is readily marketable. Methane content is comparable to that found in natural gas (90-99% for samples included in table 29 compared to an average of approximately 94% for natural gas). The quantity of other gaseous hydrocarbons is always less than 2% by volume and includes occasional ethane, propane, butane and pentane. Impurities may include large amounts of inert compounds like CO_2, N_2 and He with the possibility of small amounts of O_2 and H_2. No H_2S or SO_2 have been detected in coalbed gas.

Table 27 Comparison of estimated total U.S. in-place gas

Study	Total Resource In-Place (Tcf)	Recoverable Resource (Tcf)
Kuuskraa and Meyer (1980)	550	40-60
National Petroleum Council (1980)	398	45*
Sharer (GRI) (1980)	500	10-60
Rosenberg and Sharer (GRI) (1979)	72-860	16-487
National Gas Survey Task Force on Nonconventional Natural Gas Resources Federal Energy Regulatory Commission (1978)	300-850	(not reported)
Deul and Kim (1978)	318-766	(not reported)

*Assumes a price of up to $9 Mcf and rate of return of 10% (1979 dollars).

Table 28 — Gas content of U.S. coals by rank and depth (Kuuskraa and Meyer, 1980)

Rank	Depth (ft)		
	Under 1,000	1,000-3,000	Over 3,000
	cf/t	cf/t	cf/t
Anthracite and Bituminous	150	250	500
Sub-Bituminous	60	100	200
Lignite	30	50	100

The thermal quality of coalbed gas is very similar to that of high-methane-content natural gas. The coal-gas samples included in table 29 range from 973 to 1,059 Btus per cu. ft., while natural gas with more complex gaseous hydrocarbons has a slightly higher heat content averaging 1,068 Btus per cu. ft. For comparative purposes, a ton of coal containing 200 cu. ft. of natural gas with an average thermal value of 1,000 Btus per cu. ft. would contain 200,000 Btus of natural-gas thermal energy. The coal itself, exclusive of natural gas, may contain around 25,000,000 Btus of thermal energy (Tilton, 1976, p. 225). Coalbed gas is occasionally below pipeline quality in cases where heat content is below 950 Btus per cu. ft. or a high CO_2 content exists. High concentrations of CO_2 (seen in the Pittsburgh coal gas, table 29) are a potential problem to transport systems because of the corrosive nature of CO_2 when associated with water (National Petroleum Council, 1980). This difficulty can be corrected by reduction of CO_2 to a more dilute concentration before transport and utilization.

Current Research and Development

The U.S. Bureau of Mines has maintained a continuous research and development program in coalbed degasification since 1964. The historical objective of this and previous programs was to control, rather than recover, methane emissions and thereby improve mine productivity and safety. In recent years, however, an additional objective has been to demonstrate the feasibility of recovering commercial quantities of methane from virgin coalbeds as well as "gob" areas (previously mined panels or areas).

Additional research and development is being conducted by the U.S. Department of Energy (DOE) in cooperation with private industry under the auspices of the Methane Recovery from Coalbeds Project (MRCP). This project was organized in 1977 by DOE with the objective of trying to encourage the recovery and utilization of coalbed methane. To meet this end, research has been, and is continuing to be, conducted in the areas of resource estimation, location and characterization, and development of economic recovery systems and methods.

Table 29 — Composition of coalbed gas* compared with natural gas† (shown in percent)

	Pocahontas #3	Pittsburgh	Kittanning	Lower Hartshorne	Mary Lee	Natural Gas
CH_4	96.37	90.75	97.32	99.22	96.05	94.40
C_2H_6	1.39	0.29	0.01	0.01	0.01	3.80
C_3H_8	0.0147	—	—	—	—	0.6
C_4H_{10}	0.0008	—	—	—	—	0.3
C_5H_{12}	—	—	—	—	—	0.2
O_2	0.17	0.20	0.24	0.10	0.15	—
N_2	1.7	0.59	2.3	0.6	3.5	0.4
CO_2	0.36	8.25	0.14	0.06	0.10	—
H_2	0.01	—	—	—	—	—
He	0.03	—	—	—	0.27	—
Btu/SCF§	1,059	973	1,039	1,058	1,024	1,068

*Deul, M., and Kim, A.G., "Methane in Coal: From Liability to Asset," Mining Congress Journal.
†Moore, B. J., et al., "Analyses of Natural Gas of the United States," USBM IC 8302, 1966.
§British thermal unit per standard cubic foot at atmospheric pressure. Note: 252 kilogram calories per Btu and 0.0283 cubic meters per cubic foot.

Much of the research effort has been directed toward developing improved drilling, stimulation and recovery techniques. There are three basic recovery approaches under study: vertical drilling; horizontal drilling; and slant-hole, or directional, drilling. Regardless of the technique applied, premining drainage is, of course, the ideal. Drilling activity should commence some 3 to 5 years prior to mining, as a minimum, and, ideally, the time should be extended to a 10- to 15-year lead.

Vertical drilling utilizes conventional technology to drill vertical holes into either virgin seams or gob areas. Virgin areas generally require hydraulic fracturing to stimulate production. The fracturing which is required for the stimulation of the great majority of vertical holes has caused concern among mine operators who fear damage to roof rocks and the creation of hazardous conditions in advance of mining. Such concern is particularly warranted when the strata forming the roof rock are comprised of thin layers of coal and weak shale. Early tests by BOM indicated that fracturing was confined to existing zones of weakness within the coalbed itself and did not extend into overlying or underlying units (Tilton, 1976, p. 214 and 219; Deul and Kim, 1978, p. 41). More recent research studies have reported that the roof and floor strata were affected by the hydraulic stimulation (Lambert and Trevits, 1978; Mazza, 1979), but resulted in only minor mining problems. Hydraulic fracturing has been proven to be beneficial in achieving increased gas production and is especially useful in unmineable coalbeds where its effect on roof strata is not a consideration. Because it may prove useful in mineable coalbeds, proper treatment prior to mining may be required to insure mine safety. Under certain roof-rock geologic conditions such as thin, alternating coalbeds and shales, hydraulic fracturing may be undesirable.

Horizontal drilling involves the drilling of horizontal drainage holes into the seam from existing shafts, large diameter vertical boreholes, or from working faces. Such holes intersect the vertical cleats perpendicularly and allow for maximum drainage. The initial drainage shafts, if judiciously planned and sited, could be utilized in subsequent mining operations for access and or ventilation. A major drawback of this technique is the high cost incurred in sinking shafts. In some cases horizontal drilling has proved to be economically comparable to the drilling of vertical wells. Since horizontal drilling does not affect mining safety like the hydraulic stimulation associated with vertical drainage holes, it might be preferred, especially in cases where its utilization has proved to be economically comparable with vertical wells.

Slant-hole drilling is similar to the techniques involved in directional drilling from offshore platforms. Holes are drilled from the surface and then angled to intersect the coalbed and run horizontally through it. Although the target is generally rather thin and the most efficient drainage requires that the hole remain within the bed for a considerable lateral distance, slant-hole drilling can provide the recovery achieved with horizontal drilling. Problems associated with this technique include inadequate technology in such areas as bit control, downhole surveying, and dewatering techniques, along with the high cost of drilling. Development of the slant-hole drilling technique depends on solutions to these types of problems.

Benefits of coalbed degasification include the high quality of the product and the relatively low exploration cost. In addition, research shows that methane drainage will result in an increase in annual coal production of approximately six percent by minimizing or even eliminating methane-caused operating delays (Gabello, et al., 1980). According to Gabello, et al. (1980) this increase alone would offset the costs of the methane drainage system for the range of methane production rates that they analyzed (500-1,500 Mcf per day).

Obstacles to Commercialization

Despite the probable magnitude of the potential resource, there are technological, legal, environmental and economic obstacles to commercialization of coalbed gas.

Technological

Deul (1976, p. 198) considers the main impediment to coal degasification, in the long term, to be low coalbed permeabilities. Early work in the Pittsburgh coalbed has shown that unit to be an anisotropic reservoir with highly directional permeability (U.S. Bureau of Mines, 1974; Diamond, et al., 1975). This permeability generally parallels the vertical cleats which are best developed within coals between 800 and 1,200 feet (244 to 366 m) in depth (Deul, 1976). Such reservoirs would be most efficiently drained by horizontal drill holes which intersect the vertical cleats perpendicularly (Deul, 1976). H. S. Price (private communication, 1981) believes these characteristics to be anomalous to the Pittsburgh coalbed and that coalbeds are generally more isotropic in nature.

There is a definite need for methods of both continuous downhole surveying and accurate drill-bit guidance. This would permit extended, accurate, slant-hole drilling for most effective coalbed drainage without the need for fracture stimulation in most cases. An additional, logistical, problem may arise from the need to collect, and possibly treat, gas from a large number of holes.

In the deep "unmined" coals, development of well completion and stimulation technology is necessary before routine production of natural gas from coal seams can be accomplished. Problems have arisen from the casing cement causing damage to the coal seam. This problem is of particular concern in the case of multiple well completions. Proppants used in stimulation technology have also created a problem by flowing back into dewatering pumps and interrupting dewatering. Stimulation treatment in the form of hydraulic fracturing has not been successful below 2,000 feet due to apparent healing of the fractures and the plugging of casing perforations by "fines" flowing back (Gillies and Snygg, 1980).

Legal

A number of formidable issues must be resolved prior to commercialization of coalbed gas. The most important issue is the question of gas ownership. Until the courts make a final decision upon this issue, legal recovery and marketing of coalbed gas can only be carried out by a company owning both coal and oil and gas rights or specified coalbed-methane rights in an area, or when a compromise to produce the gas between two or more parties can be reached if separate ownership of mineral rights is involved. Generally, leaseholder rights are protected by law so that one leaseholder will not be injured by another leaseholder exercising his rights. In other words, coalbeds may not be tapped for gas by a petroleum company if mining safety regulations require coal pillars to be left as a barrier surrounding a well penetrating the coalbed. Likewise, the holder of a coal lease cannot prevent gas removal unless such production is inimical to coal production. Oil and gas leases give one the right to drill and produce hydrocarbons from any formation while ownership of the reservoir remains with the landowner. When long, horizontal holes are used for gas recovery, the project area may involve a number of landowners and the gas ownership problem is complicated further.

An additional problem related to the issue of mineral rights is the question of proprietary information. Conflicts may arise between the rights of confidentiality belonging to the coal operator and the objectives of the gas developer as regards resource appraisal. A final question is whether coalbed gas falls within the jurisdictional responsibilities of the Federal Energy Regulatory Commission.

Economic

Gas has been successfully produced by all the techniques described above. According to Kuuskraa and Meyer (1980), however, none of the methods has proven to be economically viable as an independent project. Additionally, Kuuskraa and Meyer believe gas production from coal seams by any of the three methods is currently justified economically only by considering the benefits obtained from faster, more efficient and safer mining which result from the gas production. C. T. Rightmire of TRW Energy Systems Group questions this conclusion based on the fact that there is currently some production of gas from coal seams (private communication, 1981). J. F. Bergquist of Southern California Gas Company also questions the conclusion expressed by Kuuskraa and Meyer regarding the relationship of the current economic viability of this resource to the benefits in mining because there has never been any complete verification of the economics of production of gas from coal seams. A verification of the economics would have to consider the level of in-place gas recovery which would be necessary to avoid the cost of mine ventilation facilities and the number and spacing of wellbores which would be required to achieve this goal (J. F. Bergquist, private communication, 1981).

The problem of economic feasibility is complicated by additional factors associated with degasification. Of prime importance is the uncertainty of gas deliverability rates which vary from a few Mcf per day to greater than 1,000 Mcf per day (Tilton, 1976). A coal operator generally wants to vent the gas as quickly as possible and cannot be restricted by the deliverability criteria of the utility company. In addition, the commercial specifications for a moisture content of less than 7 pounds of water per MMcf cannot be met by untreated coalbed gas, much of which contains as much as 400 pounds of water per MMcf (Harbaugh, et al., 1977). Finally, since, in some cases, coalbed gas is under less than hydrostatic pressure, compression as well as dewatering treatment may be required prior to introduction into distribution systems. In an effort to stimulate production of natural gas from coal seams, the Natural Gas Policy Act of 1978 deregulated "occluded natural gas produced from coal seams" which was classified as a "high-cost natural gas".

Environmental

The disposal of coalbed water is the main environmental problem associated with production of coalbed gas. Coalbed water varies dramatically in quality, ranging from potable to highly saline, and has a wide range of pH values. Production costs would increase in areas where dewatering is necessary and where water treatment is required prior to disposal. Though this water may serve to be an asset in dry regions, its production may draw down the water table enough to affect adversely surrounding wells used for such purposes as domestic or irrigation supplies.

Conclusions

In conclusion, it can be seen that a sizable potential resource of natural gas associated with coalbeds exists. Though estimates of gas in-place exhibit a wide range (72-860 Tcf), it appears most likely that between 40 and 60 Tcf of this resource can be recovered although the ultimately recoverable resource could be much larger. Though considerable research has been, and is being, conducted by both BOM and DOE, a number of technological, legal, environmental and economic problems persist. These obstacles, however, are not insurmountable. Commercial production of natural gas from coal seams appears to be possible within the next two decades and can contribute toward helping meet the energy needs of the United States. The National Petroleum Council (1980) calculates a potential annual production rate of 2.4 Tcf for the year 2,000 (assuming gas price of up to $9 MMBtu and a ten percent rate of return).

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NATURAL GAS FROM TIGHT (LOW-PERMEABILITY) FORMATIONS

Potential sandstone and siltstone gas reservoirs with permeability of less than 1 millidarcy exist both on- and offshore throughout the United States. These rock reservoirs may be geologically categorized into two broad groups. First, the dominantly nonmarine to transitional (deltaic) sands characteristic of the western intermontane basins which occur at depths ranging from 4,000 feet (1,220 m) to 20,000 feet (6,100 m) and usually contain natural gas generated via normal petroleum processes (Federal Energy Regulatory Commission, 1978). Second, the much shallower, depths generally less than 4,000 feet (1,220 m), marine-shelf sands of the northern Great Plains which contain biogenic gas (Rice, 1978, p. 44).

The major reservoirs are generally of Cretaceous to Tertiary age with additional scattered occurrences of diverse lithology ranging in age from Jurassic to Tertiary with some of Mississippian and Pennsylvanian age. Potential tight reservoirs occur in blanket- and lenticular-type formations. Blanket sands are single, relatively thin (10 to 100 feet), gas-bearing zones of generally uniform thickness that extend over a large area. Lenticular formations are composed of relatively thick sections (possibly 1,770 or more feet) containing laterally discontinuous beds scattered throughout the section. The National Petroleum Council (1980) estimates that more than 40 percent of recoverable tight-gas is contained in lenticular formations with the remaining recoverable tight-gas coming from blanket sands. Additional characteristics include low porosities of 5 to 15 percent and irreducible water saturations of 50 to 70 percent (Elkins, 1976, p. 127; Meyer, 1977, p. 645).

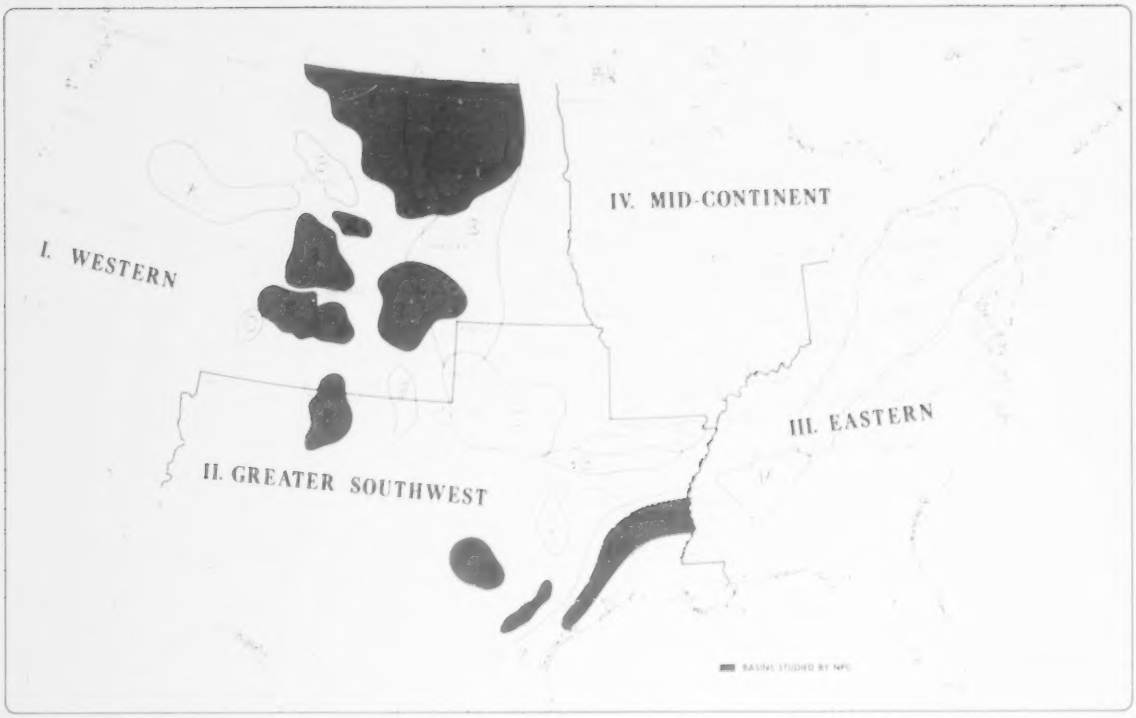
Considerable volumes of gas have long been known to exist within these tight formations. Low permeabilities and the discontinuous nature of many reservoirs make production technically difficult and expensive. The low flow rates obtained from tight-gas reservoirs have historically made exploration for and production from them economically unattractive. Economic incentive was increased by the Natural Gas Policy Act of 1978 (NGPA) which provided for a maximum price for gas from tight formations equal to 150 percent of the new onshore gas price. The maximum incentive price was subsequently raised in August of 1980 by the Federal Energy Regulatory Commission (FERC) to 200 percent of the rate allowed by the NGPA for new onshore gas. The FERC established a set of guidelines defining what constituted a "tight formation". Gas produced from formations that meet these criteria can qualify for the incentive price. Final guidelines effective September 22, 1980 are basically:

- Drilling of the well had to begin on or after July 16, 1979.
- The formation must have an estimated average *in situ* gas permeability throughout the pay section of 0.1 millidarcy or less.
- Production rates of wells completed in the formation must not exceed a flow rate, without stimulation, specified by the FERC for different depth intervals, and cannot produce more than 5 barrels of oil per day.

The Resource

Few resource estimates have been made for natural gas from tight formations. All but the most recent study (National Petroleum Council, 1980) have included only specified western interior basins without extrapolating for additional U.S. onshore and offshore areas. Figure 30 shows the location of the major basins and regions considered by the National Petroleum Council (NPC) to have tight-gas potential. Estimates of the tight-gas resource were made by a detailed formation by formation study of 12 basins (shaded in fig. 30) which account for approximately 35 percent of the total U.S. area believed to contain prospective tight-gas. Estimates were extrapolated for the remaining 65 percent of potential tight-gas areas by using basin analogs. Total in-place estimates were 444 Tcf for the 12 appraised basins and 480 Tcf for the extrapolated areas, giving a combined total of 924 Tcf for the potential tight-gas resource (table 30). Estimates for the appraised basins represent higher levels of confidence by the NPC than those for the extrapolated areas and, consequently, represent nearly half of the maximum recoverable (293 Tcf of 608 Tcf or 48%) gas. Estimates for ultimately recoverable tight-gas were made assuming four different gas prices, a 15 percent discount rate of return and two levels of technology (table 31). The base technology case was modeled after a well spacing of 160 acres and well stimulation producing 1,000-foot fractures (measured from well bore to fracture tip). The advanced technology case involved 12 wells per section, or 53-acre spacing, and fracture lengths of 4,000 feet. The advanced technology scenerio is estimated by the NPC to take 6-10 years of intensive research and 4-8 years of development before widespread application can be achieved. The contribution of recoverable gas resource by advanced technology is substantial, increasing the ultimately recoverable gas by 37 to 74 percent over the base case. The NPC estimates a range of 192 to 574 Tcf for ultimately recoverable tight-gas resource for the total U.S. (excluding Alaska). The low estimate of 192 Tcf is derived assuming $2.50/Mcf and the base technology scenerio. The high estimate of 574 Tcf assumes a price of up to $9.00/Mcf and advanced technology.

A study by Lewin and Associates (1978) analyzed the



I. WESTERN REGION
GREAT PLAINS APPRAISED
1. NORTHERN GREAT PLAINS
2. WILLISTON
ROCKY MOUNTAIN APPRAISED
3. GREATER GREEN RIVER
4. WIND RIVER
5. UINTA
6. PICEANCE
7. DENVER

OTHER KNOWN WESTERN
A. SNAKE RIVER
B. BIG HORN
C. WASATCH
D. DOUGLAS CREEK
E. WESTERN SHALLOW
CRETACEOUS TREND

II. GREATER SOUTHWEST REGION
SOUTHWEST APPRAISED
8. SAN JUAN
9. VAL VERDE-OZONA TREND
10. VAL VERDE-SONORA TREND
11. EDWARDS LIME TREND
12. COTTON VALLEY TREND

OTHER KNOWN SOUTHWEST
F. RATON
G. ANADARKO
H. OUACHITA
I. ARKOMA
J. FORTH WORTH
K. WESTERN GULF COAST

III. EASTERN REGION
L. APPALACHIAN
M. BLACK WARRIOR

Figure 30. Basins with gas in tight formations (National Petroleum Council, 1980)

potential ultimate recovery for the thirteen basins or provinces as shown in figure 31 (areas A through E and 1 through 8). Assuming the technology present at the time of the study and a gas price of $1.75 (1977 dollars) per Mcf, they estimated ultimately recoverable gas to be 70 Tcf. With reasonable technological improvements and a gas price of $3.00 (1977 dollars) per Mcf, ultimate recovery was estimated to be 188 Tcf. For purposes of comparison, the 1977 dollar prices were adjusted by the NPC to January 1, 1979, prices (table 31). In a rough comparison between the two studies, the NPC estimates appear substantially more optimistic, especially for the base case. The larger NPC estimates are due to a number of factors. First, the difference in areas appraised. The NPC analyzed 12 basins versus 13 for the Lewin study, and although 11 basins were the same, the NPC geologists evaluated 33 percent more sections. Second, there were differences in what each study considered as base and advanced technology. The larger estimates by the NPC reflect both the larger area evaluated and "increasing technical optimism of engineers two years later" (National Petroleum Council, 1980). The closer agreement in the advance case estimates is because of a 15-30 percent higher recovery efficiency expected in the Lewin study and the discounting by the NPC for poor quality portions of producing fields in their larger prospective area.

The NPC and the Lewin studies are the most comprehensive to date, but additional studies have been made. A recent study by the Gas Research

Table 30 — Comparison of estimated total U.S. in-place tight-gas resource and recoverable resource (Tcf)

	Total Gas In-Place	Technically Recoverable	Maximum Recoverable
Sharer (GRI) (1980)	(not reported)	30-150	(not estimated)
National Petroleum Council (1980)			
12 Appraised Basins	444	97-271	293
101 Extrapolated Basins	480	95-303	315
Total	924	192-574	608
Lewin and Associates (1978)			
13 Basins	409	70-188	(not estimated)
National Gas Survey Task Force on Nonconventional Natural Gas Resources, Federal Energy Regulatory Commission (1978)			
5 Basins	793	(not estimated)	(not estimated)
National Gas Survey Task Force U.S. Federal Power Commission (1973)	600	240-300	(not estimated)
Rice (1978)			
Northern Great Plains Province	100	(not estimated)	(not estimated)

Table 31 — Estimates of recoverable tight gas (Tcf)

Lewin and Associates (13 Basins) (1978)								
January 1, 1979, Price*	$2.12		$3.64		$5.45			
Base Technology	69.7		100.3		107.5			
Advanced Technology	149.3		181.5		187.7			
National Petroleum Council (1980)								
January 1, 1979, Price	$2.50		$3.50		$5.00		$9.00	
Number of Basins	12	113	12	113	12	113	12	113
Base Case**	98	192	137		164	364	193	408
Advanced Case**	144	333	192		229	500	271	574
Sharer (GRI) (1980)								
1979 Dollars	$3.12		$4.50		$6.00			
Existing Technology	30		45		60			
Advanced Technology	100		120		150			

*Lewin estimates were made using mid-1977 dollar prices which, for purposes of comparison, were adjusted to January 1, 1979, levels by NPC utilizing the IPAA price index for drilling and equipping wells.

**Assumes a 15% discount rate of return.

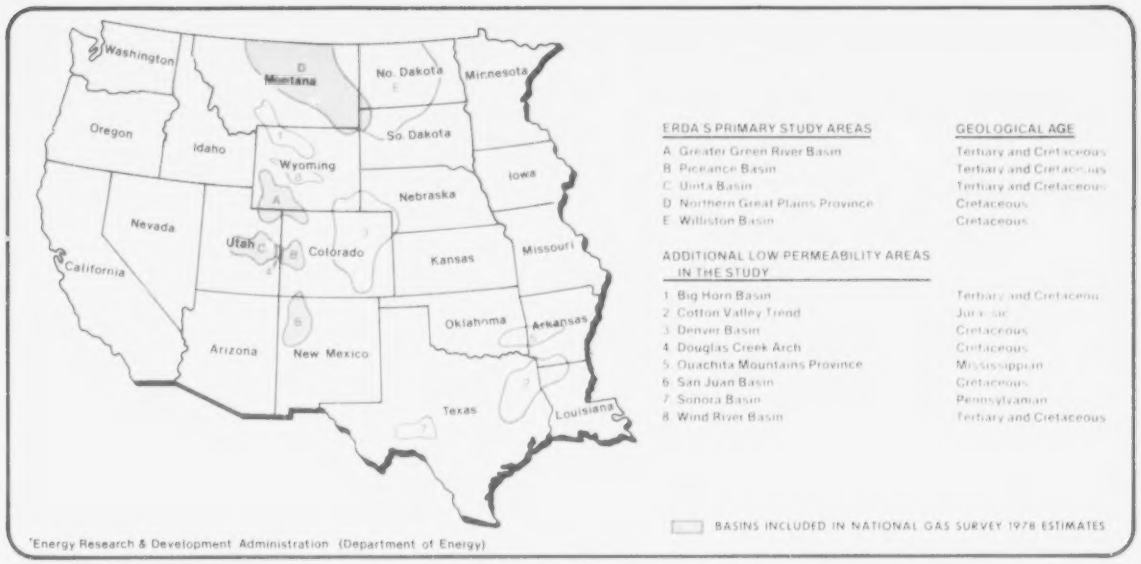


Figure 31 — Location of Western tight sands (After Kuuskraa, et al., 1978)
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Table 32 — Comparison of estimates of gas resources in tight sandstones

	National Gas Survey Task Force U.S. Federal Power Commission (1973) (after Meyer, 1977)			Lewin and Associates (1978)	
	Depth interval (ft)	Area (mi^2)	Gas in place (Tcf)	Area (mi^2)	Gas in place (Tcf)
Piceance basin					
Category 1	5,600- 8,750	550	103.2		
Category 2	5,600- 8,750	650	103.9		
Total		1,200	207.1	855	35.5
Green River basin					
Category 1	8,000-12,000	140	37.1		
Category 2	9,500-15,800	500	108.4		
Category 3	9,000-12,000	500	94.5		
Total		1,140	240.0	870	90.5
Uinta basin					
Category 1	8,000-11,000	300	101.6		
Category 2	8,000-11,000	200	47.5		
Total		500	149.1	996	50.2
TOTAL		2,840	596.2	2,721	176.2

Institute (Sharer, 1980) estimates that 30 to 150 Tcf of gas are recoverable within a range of $3.12 to $6.00 per Mcf and using two levels of technology (table 31). No estimates were reported for total gas in-place.

In 1973, a National Gas Survey (N.G.S.) Task Force of the U.S. Federal Power Commission (now the Federal Energy Regulatory Commission) focused on the potential within the Mesa Verde, Ft. Union and associated formations of the Piceance, Green River and Uinta basins (A, B, C, figure 31) (U.S. Federal Power Commission, 1973). Using volumetric comparisons, the N.G.S. report concluded that as much as 600 Tcf of gas is in place within the three basins (table 30), but cautioned that this was only an order-of-magnitude estimate. As shown in table 32, the 1973 N.G.S. Task Force qualified its estimates by reporting gas-resource figures in three confidence categories reflecting the reliability of supporting data. Category 1 indicates reasonable certainty based upon firm well control. Whereas, Category 3 includes more speculative resources. The N.G.S. study also concluded that 40 to 50 percent of the estimated 600 Tcf of gas in-place could ultimately be recovered using advanced stimulation techniques. In contrast to this study, estimates by Lewin and Associates for the same three basins were markedly smaller, namely, 176 Tcf of gas in-place instead of 596 Tcf. They cited two major factors for this decrease. First, more recent drilling and analysis showed that the net pay thicknesses of the tight formations were less than one half that initially estimated by the N.G.S. Task Force. Second, research had shown that the gas saturation and gas-filled porosities were much lower than estimated by the N.G.S. Task Force.

A more recent review of potential gas in tight formations was made by a second advisory task force (National Gas Survey Task Force on Nonconventional Natural Gas Resources) to the Federal Power Commission (now the Federal Energy Regulatory Commission) in 1977 (Harbaugh, et al., 1977, p. 91). The final report was published in 1978 by the Federal Energy Regulatory Commission. This report concluded that the 600 Tcf in-place resource estimated in 1973 was a valid approximation, yet cautioned that subsequent tests had encountered reservoir flow capacities far below those previously predicted. Therefore, while the total resource in-place may have remained unchanged, its attractiveness as a production target and, thus, the volume of ultimately recoverable gas, is considerably diminished. The 1978 report added two other areas with the potential tight sandstone gas resources to the three established previously: (1) the northern Great Plains province of Montana and the Dakotas, containing an estimated 130 Tcf of gas in-place; and (2) the San Juan basin of northern New Mexico with approximately 63 Tcf of gas in-place. The total potential in-place resource from all five areas then becomes 793 Tcf (table 30).

Finally, Rice (1978) has prepared a separate estimate for the northern Great Plains province. He has appraised the total gas in-place within the shallow reservoirs at 100 Tcf.

Current Research and Development

Recent research and development relative to the potential gas resource of tight sands has concentrated on enhancement of reservoir drainage and formation evaluation. Two methods of enhancing reservoir drainage through the development and maintenance of extensive fracture systems have been investigated: nuclear-explosive stimulation and massive hydraulic fracturing.

Since 1967, three nuclear stimulation experiments have been conducted: the Rio Blanco and Rulison Projects in the Piceance basin, and Project Gasbuggy in the San Juan basin. The objective in all three tests was to create a rubble chimney which would act as an enlarged wellbore pressure sink to provide vertical communication between sandstone reservoirs otherwise isolated by interbedded shales (Luetkehans, 1976; Harbaugh, et al., 1977, p. 72; and Stosur, 1977).

Though these tests demonstrated the technical feasibility of using nuclear explosives to stimulate gas production, the resulting productivity fell far below expectations. Three reasons for this have been postulated (Stosur, 1977, p. 712): (1) The matrix permeability of host formations was grossly overestimated by anywhere from 1 to 10 orders of magnitude depending on the test; since 99 percent of the projected drainage area was intentionally beyond the effects of the fracturing, it remained dominated by ultra-low matrix permeability (about 0.001 md for Project Gasbuggy versus the predetonation estimate of 0.1 md); (2) the post-explosive closing of newly-created unsupported fractures and greater water influx result in decreased relative permeability to gas; and (3) glazing of the explosion cavity by melting rock.

The National Gas Survey study (Federal Energy Regulatory Commission, 1978) reported that stimulation by nuclear-explosive fracturing did fall within the inferred range of enhancement and also found that it was economically comparable to alternative techniques. Stosur, on the other hand, found nuclear stimulation about one order of magnitude more expensive than massive hydraulic fracture treatments (1977, p. 699). The questionability of the effectiveness of nuclear stimulation, its expense relative to other stimulation techniques, and most important, the tremendous public concern about the dangers of radiation have reduced the earlier interest in pursuing nuclear stimulation techniques. There are currently no active plans for additional research and development in this area.

As an alternative to nuclear-explosive fracturing, massive hydraulic fracturing has emerged as a viable method for stimulation of tight sandstone reservoirs. Massive hydraulic fracturing is an amplification of older hydraulic fracturing techniques and involves the pumping of large volumes of fluids and proppant into a well under high pressure to create and maintain fractures up to thousands of feet long and hundreds of feet high. Today, typical massive hydraulic fracture treatments involve from 100,000 to 1,000,000 gallons of fluid and up to 2.5 million pounds of proppant (National Petroleum Council, 1980). This technique has been most successfully employed in the blanket-type formations of the Cotton Valley, Denver, Green River, San Juan and Sonora basins. In some cases, effectively propped fractures several thousand feet long have been achieved. However, significant advances in technology must be made before widespread, effective application of massive hydraulic fracturing can be accomplished in all basins. Advanced technology is particularly necessary in lenticular-type formations where several potential pay zones may not even be penetrated by the wellbore, and extensive fractures are necessary in order to provide conduits along which gas can reach the wellbore.

There is considerable activity among petroleum service companies, individual research departments of major companies, and the academic community toward improved formation-evaluation techniques for shaly sands. The thin, discontinuous nature of such potential reservoirs in conjunction with their exceedingly low permeabilities stretches available formation evaluation technology to its limit. For example, the effective permeability of the Gasbuggy reservoir was about 1/20th of what was predicted based upon standard industry methods of low pressure measurement on dried core plugs (Randolph, 1976b, p. 183). Similar uncertainties arise in attempting to estimate the net and associated water saturations within a large vertical interval (Randolph, 1976a, p. 162).

Obstacles to Commercialization

There are both economic and technical barriers to the large-scale development of natural gas within tight sands, but no insurmountable political, legal, or social obstacles appear to exist.

Technological problems center around the previously mentioned stimulation methods and formation evaluation research. The extremely low permeabilities, together with the lenticularity of many tight-sand reservoirs, present problems in effective formation stimulation. Massive hydraulic fracturing will, hopefully, prove effective in most cases but, as yet, it has only been tested successfully in blanket-type sands. Additional technical problems are presented by the occasional presence of swelling clays and the inability to predict accurately the reservoir characteristics of tight sands. As yet, key parameters such as effective permeability, water and gas saturations and net pay can only be approximated. Such values must be known with relative certainty before expensive advanced-stimulation projects can be evaluated from an economic viewpoint. In addition, prediction and knowledge of fracture directions out from the wellbore would be advantageous in deciding on optimum well-site locations for effective field development. The volume of recoverable natural gas from tight sands is very closely linked to the cost of the stimulation procedure and to the sale price of gas.

Conclusions

An in-place resource of at least 924 Tcf of gas probably exists within the tight-sand reservoirs of the U.S. Between 192 and 574 Tcf may ultimately be recovered given reasonable prices for natural gas and normal improvements in technology. The western basins alone contain 409 to 793 Tcf with ultimately recoverable resource estimated at 30 to 300 Tcf.

References for Natural Gas from Tight (Low-Permeability) Formations

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NATURAL GAS FROM DEVONIAN SHALES

Organic-rich shales of Devonian age underlie a major portion of the Appalachian, Michigan and Illinois basins. They represent the marine part of a delta which built westward during the Devonian period (about 350 million years ago). These organic-rich shales are reported to contain between 5 and 25 percent organic matter by Duncan and Swanson (1965), but W. F. Morse (private communication, 1981) indicates that about 10 percent of the samples analyzed by Columbia Gas System Service Corporation have an organic content of less than 0.5 percent. Deposition of these sediments occurred over most of the mid-continent region. Tectonic uplift and erosion has decreased the areal extent of these shales to present-day levels, and their preservation is most pronounced in basinal areas. In regions of these basins where these shales have undergone a sufficient thermal history (via burial) to effect maturation of their organic material to gas, a potentially large natural gas resource exists.

Figure 32 illustrates the areal extent of the Devonian shales considered by the National Petroleum Council (1980) to be gas-bearing. The resource base underlies approximately 175,000 square miles (453,000 square kilometers) mostly at depths ranging from 1,000 to 6,000 feet (610 to 1,830 m). These shales have a long history of natural gas production which has been of considerable local importance and are best classified as an underdeveloped, rather than nonconventional, resource. The legal and environmental problems associated with gas production from Devonian shales are the same issues confronting exploitation of conventional gas resources and are not considered to be significant hindrances to large scale commercialization. Underdevelopment of the Devonian shales is largely due to economic limitations. Exploitation involves large capital expenditure, and, although gas production is long-lived, the low flow rates achieved from wells result in a low rate of return on investment.

The first U.S. well drilled specifically for natural gas produced gas from Devonian shales near Fredonia, New York, in 1821, 38 years prior to Drake's historic oil well (McCaslin, 1978, p. 175). Since 1921, relatively modest volumes of natural gas have been commercially produced from Devonian shales. Currently, the most significant producing areas are in Ohio, West Virginia and Kentucky, with the latter two being of prime importance. Present production is estimated to be about 100 Bcf per year (Kuuskraa and Meyer, 1980). Actual shale production for Devonian shales may, in fact, be lower due to co-production from other zones. Brown (1976, p. 86) has estimated that 10 to 25 percent of gas production attributed to Devonian shales may actually be derived from overlying Mississippian carbonates and sandstones.

The Resource

Devonian shale matrix is characterized by low porosities of generally 3 percent or less and very low permeabilities of .005 millidarcy or less (Smith, 1978). Consequently, gas production is controlled by permeable patterns, primarily fractures (naturally occurring or induced) with additional influence from silts. A fair correlation exists between potential production and organic-rich shale thickness, with most commercial production coming from the thick shales located in the southwestern portion of the Appalachian basin.

It is not known whether gas production from the Devonian shales is from desorption of gas from the matrix or from free gas trapped in natural fractures of the shale. Proponents of the hypothesis that production is from free gas believe that the contribution of gas desorbed from the matrix is negligible and not producible by conventional drilling. Research being carried out at Juniata College, however, has shown that gas is in adsorbed form (Smith, 1978). If this is, in fact, the case, then gas content is not a function of porosity. Evaluation of the nature of produced gas is necessary before the actual recoverable resource can be known with greater certainty. Lewin and Associates (1978) estimate that if matrix gas is actually desorbed from the organic matter, the gas resource is an order of magnitude larger than that estimated for free gas. It has been estimated that only 2 to 10 percent of the original gas in-place (adsorbed / free gas) is recoverable (Avila, 1976, p. 83; Brown, 1976, p. 86; Ray, 1977, p. 682). The remaining 90 to 98 percent of the total gas resource would require some form of in-situ process for liberation, such as crushing and heating or even retorting.

Figure 32 — Geographic outline of potential Devonian shale areas. The area shown represents that portion within each basin considered by the Devonian Shale Task Group (National Petroleum Council, 1980) to have shale gas potential and does not necessarily represent the entire Devonian shales that exist in the basins. (Source, National Petroleum Council, 1980)

Because of a general lack of complete geologic data and different estimation techniques, there is a wide variation in resource and recoverable resource estimates (table 33). Much of the variation in estimates reflects varying assumptions relative to the gas content, reservoir potential and drainage efficiency of the Devonian shales. Many geologists and engineers would consider the low estimates to be unnecessarily conservative and to reflect only a portion of the potential resource and potential area. They would also consider the high estimates to be unduly optimistic in extrapolating the productivity of currently producing wells over the entire prospective area. Much of the data used for resource estimates comes from the Appalachian basin where production has been in progress for many years. Little is known about the Illinois and Michigan basins and the lack of data makes estimation even more difficult. Direct extrapolation is not possible due to the differences between basins. Research conducted by the Eastern Gas Shales Project (a program sponsored by the Department of Energy) has reported the gas content of Applachian basin Devonian shale samples to have a mean value of .52 cu. ft. cu. ft. shale. This value is considered to be optimistic by Columbia Gas System Service Corporation which considers a mean gas content of about 0.2 cu. ft. cu. ft. shale to be more representative (W. F. Morse, private communication, 1981). Samples from the Illinois basin while having a higher organic content have a mean gas content of .42 cu. ft. cu. ft. shale due to a lower degree of thermal maturity. Analyses for the Michigan basin have yet to be made (Wise, 1979b).

A task group appointed by the National Petroleum Council (NPC) at the request of the Secretary of Energy has recently estimated the total in-place natural gas resource within the Devonian shales of the Appalachian basin to be from 225 to 1,860 Tcf (National Petroleum Council, 1980) (table 33). The low estimate of 225 Tcf was computed considering only the resource which might be present in the more highly organic-rich black shales. The high estimate of 1,861 Tcf is based on gas derived from both the richer black shales and the less prolific organic-lean gray shales. The task group used both published U.S. Geological Survey sample thickness figures (identified by color) and shale radioactivity as measured by gamma-ray well logs to determine black shale thicknesses. Gray shale thickness was derived by subtracting calculated black shale thickness from the total shale thickness. The resource estimates for the Appalachian basin were made using gas content values of 0.6 standard cubic feet of gas (scfg) per cubic foot of shale (cfs) for black shales and 0.1 scfg/cfs for gray shales. Total producible gas (regardless of price or technology) from Devonian shales in the Appalachian basin is estimated by the task force to be 50 Tcf. The task force also made estimates of total in-place gas resource for the Michigan and Illinois basins. Estimates for the Michigan basin were made using the same approach as for the Appalachian basin. In the Illinois basin it was not possible to differentiate between the black and gray shales, and a gas content value of 0.62 scfg/cfs was applied to the total shale thickness. A total of 160 Tcf of gas in-place was estimated for the Michigan and Illinois basins. Production data from these basins were thought by the task force to be insufficient for reliable estimation of recoverable resource.

Kuuskraa and Meyer's (1980) estimate for the Appalachian basin compares favorably with the NPC estimates and concludes that there are 400 to 2,000 Tcf of gas in-place. Eighty trillion cubic feet (80 Tcf) is considered to exist as free gas and of this, 10-50 Tcf is the ultimately recoverable resource. Kuuskraa and Meyer report total gas in-place within other basins to be 1,900 Tcf, or one order of magnitude larger than the NPC estimate for the Illinois and Michigan basins. Combining estimates of all basins, according to Kuuskraa and Meyer, gives a total gas in-place of between 2,300 and 3,900 Tcf.

The National Gas Survey Task Force on Nonconventional Natural Gas Resources (Federal Energy Regulatory Commission, 1978) considered 285 Tcf as a most likely gas in-place figure with 60 Tcf potentially recoverable. The U.S. Geological Survey (DeWitt,

Table 33 — Estimates of Devonian shale resource

STUDY	GAS IN-PLACE (Tcf)		RECOVERABLE RESOURCE (Tcf)
	Free Gas	Total Gas	
National Petroleum Council (1980)			
Appalachian Basin		225-1,860	50
Other Basins		160	(not estimated)
Kuuskraa and Meyer (1980)			
Appalachian Basin	80	400-2,000	10-50
Other Basins		1,900	(not estimated)
Total (Free and Adsorbed Gas)		2,300-3,900	10-50
Federal Energy Regulatory Commission (1978)			
Appalachian Basin		285	60
Lewin and Associates (1978)			
Appalachian Basin	80		46
Smith (1978)			
5-State Area in Appalachian Basin		206- 903	
U.S. Geological Survey (1976) (cited in DeWitt)		500- 600	(not estimated)

1976, p. 113) estimates that between 500 and 600 Tcf of total gas in-place exists within the Devonian shales. They did not make an estimate of recoverable resource. Smith (1978), of the Columbia Gas System Service Corporation, has published estimates of total gas in-place resource for a five-state area including West Virginia, Kentucky, Ohio, Pennsylvania and Virginia which range from 206 to 903 Tcf. This range in magnitude reflects varying assumptions relative to the gas content, reservoir potential and drainage efficiency of the Devonian shales. Even though estimates show a wide variation in ranges, they show relatively good agreement on what is considered to be recoverable.

Current Research and Development

The most persistent difficulty encountered in the production of natural gas from shale is the lack of adequate matrix permeability. Production is, therefore, confined to regions which have extensive natural permeable zones or where it is possible to induce fracturing by stimulation techniques. Historically, only about 5 percent of shale completions have had natural flows in commercial quantities. Approximately 40 percent of such wells had no measurable gas flow prior to stimulation, and 11 percent remained nonproductive even after stimulation (Ray, 1976, p. 682-683). The traditional stimulation method has been the use of openhole explosives. This technique has proven to be rather inefficient because of its limited radial effect and because it cannot be directed toward just the productive intervals but affects many others as well. During the last 10 to 15 years, conventional hydraulic-fracturing techniques have been adapted to shale-well stimulation. A study comparing these two stimulation techniques showed that conventional hydraulic-fracturing resulted in a 57 percent improvement in production relative to traditional shooting techniques. Maximum improvement was shown in wells producing less than 100 Mcf per day after stimulation and diminished with increasing production until no difference was observed between the two techniques in stimulated wells producing over 300 Mcf per day (Ray, 1976). Most recently, research has been directed toward testing more advanced techniques. Preliminary investigations in Kanawha County, West Virginia, showed a 230 percent average increase in production over traditional shooting methods for wells stimulated either through fracturing using a fluid combination of methanol, propanol and carbon

dioxide or through shooting with liquid explosives. These results compared to an average increase of 80 percent in the conventional hydraulically-fractured wells relative to the ones stimulated with traditional shooting techniques (National Petroleum Council, 1980).

Research is also being carried out to develop exploration techniques for finding gas in the Devonian shales. Since gas production is most successful in areas having extensive fracturing, it is advantageous to be able to know the cause of the fracturing and how it might be located. Structural studies of the Cottageville Gas Field located in western West Virginia indicate the possible association of fractures with basement fault movement. Preliminary investigations into the relationship of gas accumulations to geologic parameters carried out in the Big Sandy Field of eastern Kentucky show that production is related to preferential fracture directions in the shales. These fractures are postulated to be related to tensional stresses associated with basement faulting, especially thrust faulting (de Wys and Shumaker, 1979). While more research is necessary to prove these relationships, they may provide a means for predicting gas accumulations in the future (Wise, 1979a).

Extensive research related to the Devonian shale gas resource is currently being conducted by the Department of Energy and various industry organizations. In 1976, the Department of Energy (then ERDA) began the Eastern Gas Shales Project for the purpose of determining the potential gas resources for the Devonian shales and developing improved exploration and recovery techniques. In addition, the Gas Research Institute has been investigating shale properties fracture orientation and geometry and the effect of fracture and treatment fluids on shale formations. Development of the gas resource by drilling and application of advanced hydraulic and foam fracture techniques is actively being pursued by gas companies, especially Columbia Gas, Consolidated Natural Gas, Kentucky-West Virginia Gas Company, Mitchell Energy and Allegheny Land and Minerals (Sharer, 1980).

Obstacles to Commercialization

Economic factors are considered to be the most significant hindrance to large-scale commercialization. Despite the fact that Appalachian production is located near the large Eastern energy markets, deliverability rates and drilling costs interact to make even successful wells only marginally economic. While shale wells often outperform more conventional wells on a cumulative production basis, their slow rates of production result in a slow rate of return on invested capital, often requiring 7 to 12 years to pay out (Avila, 1976, p. 73). In addition, in any given year there is approximately a 25 percent cost increase in drilling average shale wells over the national average cost for similar, more conventional wells (Ray, 1977, p. 692). This additional expense may be attributed to locally rugged terrain, additional casing required to protect coal seams, and remote locations relative to many service companies. Under such conditions, the further cost associated with advanced stimulation techniques is often economically unsound.

Conclusions

Studies find an in-place natural gas resource ranging between 285 to 3,900 Tcf exists within the Devonian shales of the Appalachian, Illinois and Michigan basins. Estimates of ultimately recoverable resource using existing drilling and stimulation technology ranges between 10 and 60 Tcf for the Appalachian basin only. Recoverable resources have not been estimated for the other basins. The greatest hindrance to larger scale commercialization of this resource is the marginally favorable economic environment. This, in turn, is a reflection of the low permeabilities and modest production rates associated with shale wells.

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GAS HYDRATES

Gas hydrates were first brought to the attention of the petroleum industry by Hammerschmidt (1934) who noted that under certain conditions natural gas pipelines were plugged due to the formation of hydrates. Later reports by Soviet scientists (Makogon, 1965) stated that naturally occurring gas hydrates had been encountered in deep permafrost areas and that these hydrates represented possible gas resources of more than 535 trillion cubic feet (Chersky and Makogon, 1970). These reports and others around the world have greatly stimulated interest in gas hydrates.

Gas hydrates are an ice-like mixture of gas and water, a type of clathrate, in which gas molecules are trapped by a framework or "cage" of water molecules (Pauling and Marsh, 1952). Gas hydrates form in a gas-fresh water system under univariant pressure-temperature conditions such that, depending on the pressure, hydrates can be stable from subzero temperatures to more than 30° Celsius (fig. 33). Impurities in natural gas (CO_2, C_2H_6, H_2S and C_3H_8) increase the hydrate stability field and the presence of salt (NaCl) decreases the hydrate stability field (Katz, et al., 1959).

Potentially, large quantities of natural gas (either biogenic or thermal methane plus ethane, propane and other light hydrocarbons) can be trapped in gas hydrates. Also, large quantities of free gas or other

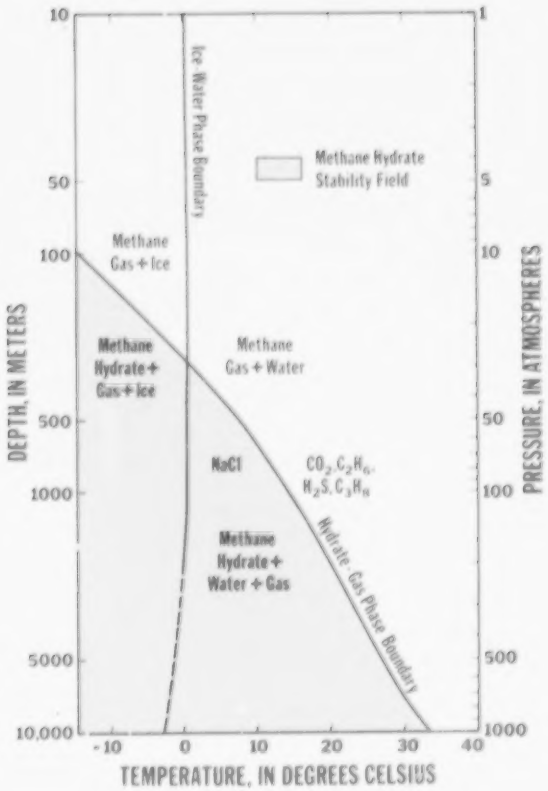

Figure 33 — Gas hydrate stability field (redrawn from Katz, et al., 1959, by Kvenvolden and McMenamin, 1980)

hydrocarbons can be trapped beneath impermeable gas hydrate layers. Due to the dimensions of the hydrate crystalline lattice, very light gases such as hydrogen and helium pass through the clathrate and cannot be trapped, whereas isobutane is the maximum-sized hydrocarbon which can be incorporated into the structure. Though hydrates are nonstoichiometric compounds, an ideal methane-saturated fresh water system at standard temperature and pressure can yield approximately 170 m^3 of free gas per m^3 of hydrate (or 132 ft^3/ ft^3) (Makogon, 1969). These data indicate that gas hydrates could be a much greater resource per unit volume than conventional free-gas reservoirs at depths of burial less than 1,500 meters.

Theoretically, the proper conditions (high pressure, low temperature) for gas-hydrate formation exist in the geologic environment in permafrost areas and within marine seafloor sediments. Drilling in Arctic areas by the Soviets in the early to mid-sixties and in offshore areas by the United States in the seventies have confirmed the presence of gas hydrates in both

environments. Early estimates of resources are subjective, at best, but all estimates indicate that gas hydrates are a possible enormous resource.

This paper will review the geologic occurrence and estimated resources of gas hydrates and present the numerous problems which are anticipated in exploiting this resource.

Geologic Occurrences of Gas Hydrates

Temperature and pressure conditions in the earth's crust vary, contrary to ideal conditions for the formation of gas hydrates. Hydrate formation is favored by high pressure and low temperature (generally less than 35° C.), but temperature in the earth's crust increases along a geothermal gradient with increasing depth of burial and overburden pressure. Therefore, gas-hydrate formation is limited to the shallow, cool regions of the crust where sufficient biogenic or thermal light hydrocarbons are available.

Permafrost Areas

Permafrost presently covers about 23% of the earth's landmass, including 75% of Alaska, 63% of Canada and 47% of the U.S.S.R. (Black, 1954). The depressed geothermal gradient in permafrost areas theoretically allows for gas-hydrate formation from about 200 to 1,000 meters below the surface (fig. 34).

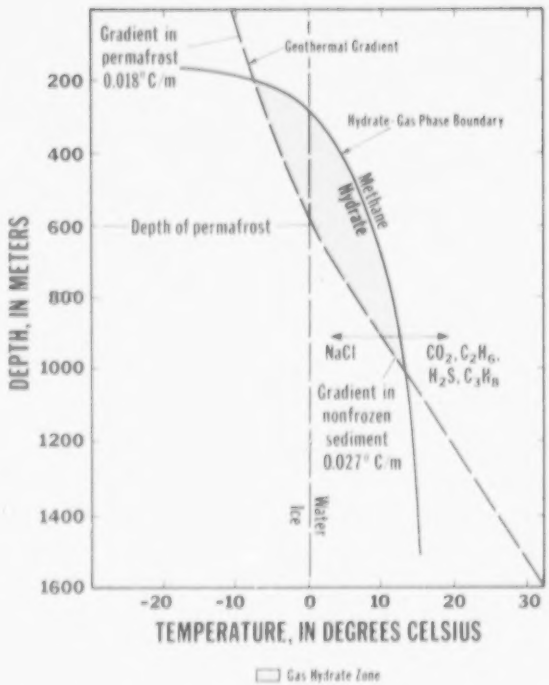

Figure 34 Zone of gas hydrate stability in permafrost areas (redrawn from Bily and Dick, 1974, by Kvenvolden and McMenamin, 1980)

Barraclough (1980) summarizes theoretical zones of hydrate stability (ZHS) for parts of Alaska, Canada and the U.S.S.R. (table 34). The average thickness of hydrate accumulations is about 700 meters, though considerable variation is noted. The bottom of the zone of hydrate stability reaches over 2,000 meters deep which is twice the depth calculated for an ideal methane-fresh water system. This greater than expected depth occurs because heavier hydrocarbons (C_2H_6, C_3H_8) and other gases (CO_2, H_2S) in the methane system extend the depth of gas-hydrate stability (fig. 33).

Known or inferred gas-hydrate accumulations in permafrost areas are shown on figure 35 (Kvenvolden and McMenamin, 1980). Table 35 summarizes evidence for gas hydrate accumulations in permafrost areas.

In the early 1960s the Soviets indicated that possible gas hydrates were encountered in drilling tests in Siberia. By 1969 to 1970, the development of the Messoyakha field, in which 54% greater gas by volume than anticipated from a free-gas accumulation was recovered from gas-hydrate formations, led to a resource estimate of 535 Tcf for gas hydrates in northeastern Siberia (Chersky and Makogon, 1970). Both gas hydrates and free gas trapped beneath the low-permeability hydrate layer are reportedly being produced in the Messoyakha field (Dobrynin, et al., 1979). Gas-hydrate production is being enhanced by the injection of methyl alcohol to induce dissolution (Oil and Gas Journal, 1978). Recent Soviet sources claim that there are more than thirty known gas-hydrate accumulations in Siberia (D. Sloan, personal communication, 1980).

In 1971 to 1972, drilling in the North Slope of Alaska and Mackenzie Delta of Canada (Bily and Dick, 1974) encountered gas hydrates, but both sites yielded poor production tests. Drilling in Canada's Arctic Archipelago also encountered gas hydrates but no information is available on results of tests (Hitchon, 1974).

Until recently the presence of gas hydrates in permafrost areas was not conclusively proven. Gas-hydrate accumulations are generally inferred from drilling or well-log characteristics which are very similar to those encountered when drilling through normal permafrost layers:

(1) small or no spontaneous potential (SP) deflection on electric logs (due to low permeability of hydrate-cemented rock).

Table 34 — Zones of gas hydrate stability in permafrost areas
(for 0.6 gravity natural gas)
(Barraclough, 1980)

	Depth to Bottom of Permafrost (m)	Top of ZHS (m)	Bottom of ZHS (m)	Stratigraphic Thickness (m)
Alaska				
Cape Simpson	290	290	630	340
Cape Thompson	360	360	1,420	1,060
Point Barrow	400	400	1,020	620
Prudhoe Bay	610	610	1,220	610
Canada				
Resolute, N.W.T.	370	370	760	390
Mackenzie Delta	—	190	1,860	1,670
Sverdrup Basin	—	140	1,270	1,130
W. Arctic Islands	—	140	1,100	960
E. Arctic Islands	—	180	960	780
USSR				
Messoiakhskoe	450	450	1,050	600
Viliui	—	330	1,180	850
Markhin	1,440	100	2,200	2,100
Namanin	85	200	1,650	1,450
Olekmin	100	150	2,000	1,850
Ilychir	100	100	500	400
Sredne-Botuobin	620	100	2,000	1,900

Figure 35 — Known and inferred gas hydrate accumulations
in permafrost areas (No. 1-5; Table 35)
in offshore areas (No. 6-15; Table 36)
(modified from Kvenvolden and McMenamin, 1980)

Table 35 — Gas hydrates in permafrost areas
(Kvenvolden and McMenamin, 1980)

Number on Fig 3	Location	Permafrost thickness (m)	Predicted depth range of hydrate (m)	Geophysical evidence	Geochemical evidence	Research organization	References
1	Messoyakha gas field and northwestern Siberia, U.S.S.R.	450	250-870		90 pct. or more methane in gas analysis; large volume of gas from thawed cores.	U.S.S.R.	Makogon and others, 1971.
2	Mackenzie Delta, Northwest Territories, Canada	610	820-1100	Well logs: small deflection in SP, high resistivity; high velocity sonic log; over-gage caliper log.	do.	Imperial Oil Ltd.	Bily and Dick, 1974.
3	West of Prudhoe Bay, Alaska, U.S.A.	610	210-1100	Well logs: high resistivities; high velocity sonic log; gas kicks in mud logs.	do.	Exxon	R. D. McIver, written commun., 1979.
4	Arctic Archipelago, Northwest Territories, Canada	530	No data in print.		No data in print.	Dome Petroleum Ltd.	Hitchson, 1974.
*5	Vilyuy Basin, Yakutia, U.S.S.R.	> 500	do.		do.	U.S.S.R.	Makogon and others, 1972.

*Up to 35 sites of gas hydrate accumulation are reported in northeast Siberia.

(2) high resistivity on electric logs (fresh water system).
(3) high sonic-log velocity (due to solid hydrate framework).
(4) over-gauge boreholes (hydrates are hard to drill but the borehole eventually enlarges due to decomposition and loss of wellbore support).

Gas hydrates can be distinguished from normal permafrost in instances where mud logs record high-level gas "kicks" in addition to the characteristics stated above. The Soviets also report a decrease in bottom-hole temperature and water freshening during gas hydrate recovery (Trofimuk, et al., 1980).

The first conclusive evidence of gas-hydrate formation in permafrost areas was obtained from pressured core samples from an ARCO/Exxon well on the North Slope of Alaska in the West Prudhoe Bay field (Kvenvolden and McMenamin, 1980). Pressures in the core barrel built up repeatedly after samples were withdrawn, indicating that hydrate decomposition was maintaining equilibrium pressures. The sampled gas was 93% methane and 7% nitrogen.

The presence of significant gas-hydrate accumulations in permafrost areas throughout the world indicates that there is a high potential for this resource in permafrost areas, though information on actual resources is speculative.

Submarine Sediments

Conditions within the marine environment seem to be significantly more favorable for gas-hydrate formation than conditions in permafrost areas. Ideally, gas hydrates can form in submarine sediments below about 500 meters of water (outer continental margin) to abyssal depths (fig. 36). Gas hydrates form at the sediment-water interface and the thickness of gas-hydrate accumulations increases with the height of the water column due to increased pressures (nearly 1,000 meters of hydrate form under 3,000 meters of seawater; fig. 36). This data indicates that conditions necessary for hydrate formation exist in about 90% of the world's ocean seabeds (A.G.A., 1979).

Theoretically, gas hydrates could form in the water column where natural gas is seeping from submarine sediments. But hydrates are lighter than seawater (0.81-0.93 g/cm^3) and would float up to warmer zones in the water column and dissipate.

It is important to emphasize that different processes are active in the marine environment compared to permafrost areas. Biogenic gas is being formed in recent submarine sediments below the sediment-water interface which are also within a hydrate stable environment. This in-situ production and entrapment of gas could result in large accumulations of hydrates, possibly with free gas trapped beneath hydrate layers.

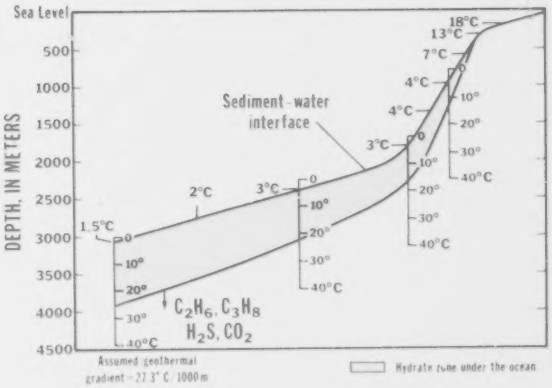

Figure 36 Zone of gas hydrate stability in submarine sediments (Kvenvolden and McMenamin, 1980)

In 1971 United States' scientists theorized that an unusual seismic reflection shield encountered by the Deep Sea Drilling Project in the Blake-Bahama Ridge of the Atlantic Ocean was caused by a phase change from hydrate to gas (A.G.A., 1979). Since then, efforts by United States' scientists and some Soviet, British and Canadian scientists, have revealed possible gas-hydrate accumulations in submarine sediments around the world (fig. 35; table 36). Zones of gas-hydrate accumulation which are predicted from geophysical evidence occur in water depths from 400-5,500 meters and are 500 to over 1,000 meters thick (table 36). Predicted depths agree well with theoretical calculations (fig. 36).

Geophysical Evidence. Recognition of gas-hydrate accumulations in submarine sediments relies primarily on geophysical evidence. Bottom-simulating reflectors have been recognized in various marine locations where hydrates are theoretically stable (table 36). A bottom-simulating reflector (BSR) is an anomalous seismic reflection which parallels seafloor topography from 100 to 1,100 meters below the sediment-water interface (about 1/2 second below the seafloor reflection). The BSR is a reverse-polarity reflection between the base of high-velocity (2.1 km/sec), hydrate-cemented sediments and underlying, low-velocity sediments with interstital water and/or free gas.

Bottom-simulating reflectors parallel seafloor topography because the hydrate-stability field is controlled by the geothermal gradient, and isotherms generally parallel bottom irregularities. The sub-bottom depth to the BSR (100 to 1,100 meters) is proportional to water depth which controls pressure-temperature conditions, though pore salinity and gas composition can shift the hydrate-stability field and, hence, the BSR (Barraclough, 1980).

Table 36 — Gas hydrates in seafloor sediments
(Kvenvolden and McMenamin, 1980)

Number on Fig. 3	Location	Water depth (m)	Predicted sub-bottom depth range of hydrate (m)	Bottom-simulating reflectors (sub-bottom depth, m)	Other geophysical evidence	Geochemical evidence	Research organization	References
6	Blake-Bahama Outer Ridge, western Atlantic, off east coast of U.S.A.	3700	0-1000	about 500		90 pct. or more methane in gas analysis; large volume of gas from thawed cores.	Lamont-Doherty, DSDP, and USGS	Parkl and others, 1970; Ewing and Hollister, 1972; Dillon and others, 1980.
7	Bering Sea, North Pacific	2000-4000+	0->1000	580-670	VAMPs, >500 m beneath the seafloor.	90 pct. or more methane in gas analysis.	DSDP and USGS	Scholl and Creager, 1973; Scholl and Cooper, 1978.
8	Beaufort Sea, Arctic Ocean	400-2500+	0-700+	100-300		No data in print.	USGS	Grantz and others, 1976.
9	Western North Atlantic	2500-3800	0->1000	500-600		do.	Lamont-Doherty	Tucholke and others, 1977.
10	Western Gulf of Mexico	1200-2000	0-500	100-1100		do.	Univ. of Texas Marine Science Institute	Shipley and others, 1979.
11	Northern Colombian and northern Panamanian coasts	1500-3000	0-800	100-1100		do.	do.	do.
12	Central America, Pacific side; Western Mexico	800-2400	0-650	100-1100		Hydrates observed; greater than 5x volume of free gas evolved from thawed core.	Univ. of Texas Marine Science Institute; DSDP	Shipley and others, 1979; Moore, Watkins and others, 1979.
13	Western Africa	2000-5500	0->1000		Pagoda structures at very shallow depth.	do.	Woods Hole, Mass.	Emery, 1974.
14	Gulf of Oman	3000	0-800		Bright spots at 600-700 m depth.	do.	Cambridge, U.K.	White, 1979.
15	Black, Caspian Seas					Hydrates observed; large volume of gas from thawed core.	U.S.S.R.	Yeframova and others, 1974; Milton, 1977.

Bottom-simulating reflectors often intersect bedding reflectors where bedding is not parallel to seafloor topography. An example from the Blake-Bahama Outer Ridge (fig. 37) illustrates how well defined the BSR is under these conditions.

It is important to note that bottom-simulating reflectors can be caused by phenomenon other than gas-hydrate formation. Temperature-controlled diagenetic effects, such as the transformation of hemipelagic diatom ooze into indurated claystone in the Bering Sea, can cause a BSR on seismic profiles (Scholl and Creager, 1973). Also, not all gas-hydrate accumulations cause bottom-simulating reflectors, especially where stratification parallels seafloor topography.

Lithification of seafloor sediments and hydrate formation may be linked. Claypool and Kaplan (1974) state that gas-hydrate formation may influence carbon dioxide and methane activities which affect pore chemistry and, therefore, influence dissolution and reprecipitation of carbonate and silica cements.

Other seismic evidence of gas-hydrate accumulations includes velocity amplitude features (VAMPs). VAMPs are narrow (1-2 km) columns of velocity "pulldown" (a concave reflection horizon) associated with a gently arched high-velocity horizon at shallow depths (Scholl and Cooper, 1978). VAMPs are observed in the Bering Sea more than 500 meters below the seafloor in association with gas-hydrate accumulations (table 36).

Pagoda structures, alternating light and dark triangular features, form due to local centers of gas-hydrate induration in West Africa at sub-bottom depths of 2,000 to 5,000 meters (Emery, 1974).

Bright spots associated with free gas trapped beneath impermeable hydrate seals are observed in the Gulf of Oman (White, 1979).

Geologic-Geochemical Evidence. Direct observation of hydrated sediments supports geophysical evidence for gas hydrate accumulations. DSDP cores from the Blake Ridge yielded high volumes of methane in excess of amounts expected if only free gas were present (Ewing and Hollister, 1972).

The Soviets report that cores from the Black and Caspian Seas were spontaneously ejected from core barrels and that hydrate crystals were observed in rock cavities (Yefremova and Zhizhchenko, 1974; Milton, 1977).

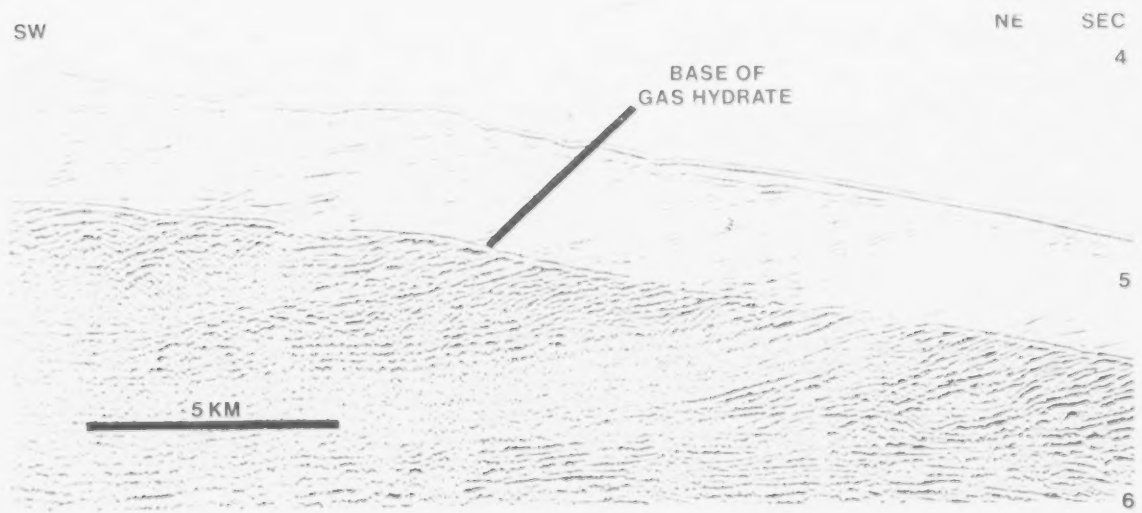

Figure 37 — Seismic profile showing gas hydrate accumulation on the east flank of the Blake Outer Ridge (Shipley, et al., 1979)

Gas hydrates were recently drilled by the Glomar Challenger at a site 100 kilometers southeast of Acapulco, Mexico, during Deep Sea Drilling Project Leg 66 (Moore, Watkins, et al., 1979). Hydrate-cemented sediments were observed on the deck before decomposing and more than five times the amount of free gas which could have been present was evolved from core samples.

Recognition of gas-hydrate accumulations in submarine sediments is in its infancy, but early evidence indicates that gas hydrates beneath the world's oceans may be a significant resource.

Gas Hydrates as Seals for Accumulations of Free Hydrocarbons

Evidence from around the world indicates that impermeable gas hydrate layers can trap free gas and other hydrocarbons in permafrost and marine environments (Makogon, 1974; Tucholke, et al., 1977; White, 1979; Shipley, et al., 1979; Hedberg, 1979; Dillon, et al., 1980). A close association of free gas and gas hydrates is expected since any change in geologic-geophysical conditions can result in the formation or dissolution of hydrates.

Several conditions of free gas-gas hydrate association can be developed:

(1) Updip migration of free gas into a zone of hydrate stability could result in self-entrapment of the gas (fig. 38).

(2) As sediments accumulate, hydrates formed near the surface will eventually be buried and encounter higher temperatures and dissolve. However, upward migration of the free gas will be halted by hydrate formation occurring in shallower horizons, so the free gas will be trapped and the reservoir will grow with time.

(3) Gas-hydrate layers often parallel sea floor topography since hydrate stability fields are determined by sub-bottom pressure and temperature conditions. Hydrocarbon traps can develop where hydrate layers form parallel to a dome or ridge on the sea floor. This type of trap is observed on seismic profiles on the Blake Ridge off southeast United States (fig. 39; Dillon, et al., 1980).

(4) Local variations in pressure-temperature conditions may also cause doming of the hydrate layer. Local increases in heat flow around salt domes beneath the continental slope of North Carolina seem to cause doming of hydrate layers which may be local traps for free gas (fig. 40; Dillon, et al., 1980).

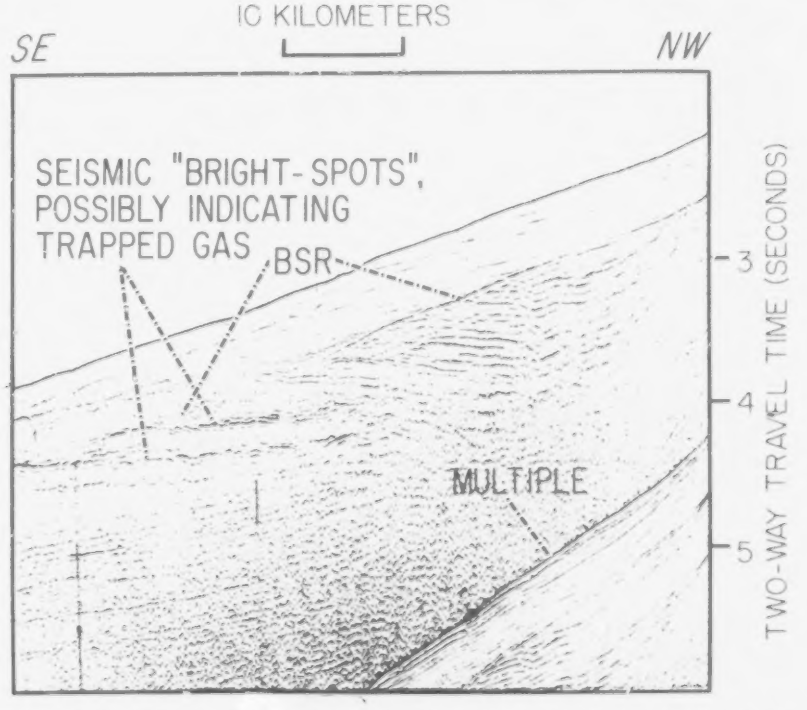

Figure 38 — Seismic profile showing gas hydrate accumulation in dipping beds (Dillon, et al., 1980)

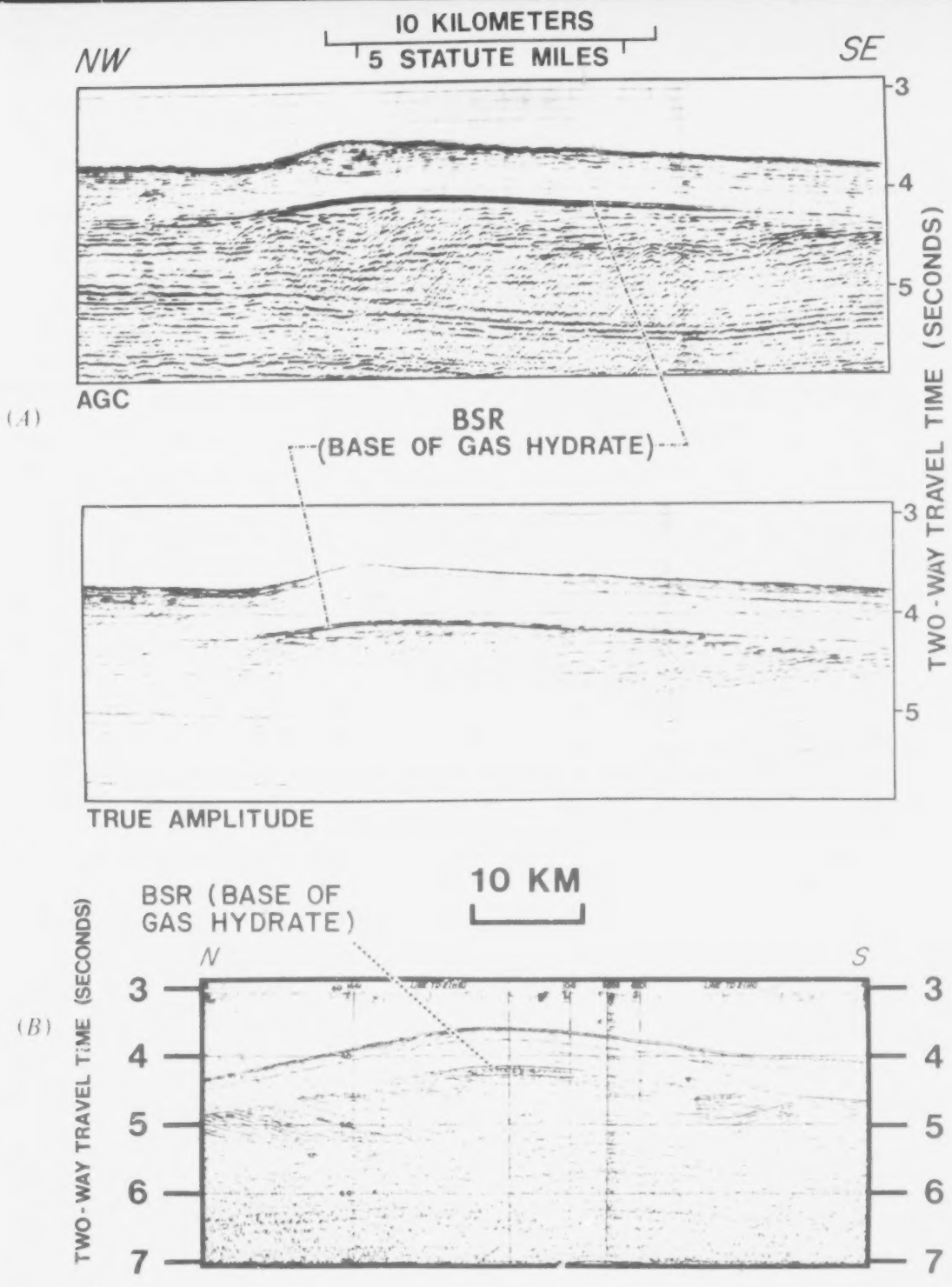

Figure 39 Seismic profiles of the Blake Ridge showing BSRs (Dillon, et al., 1980)

A is a profile approximately along the axis of the Blake Ridge off North Carolina. This broad ridge extends diagonally away from the continental slope and contains exceptionally strong BSRs that probably represent gas hydrates.

B is a profile that crosses the ridge near the right side of the section shown in *A*.

(5) Large environmental or climatic changes could be responsible for regional hydrate formation or dissolution. Trofimuk, et al. (1977) cites convincing evidence that the retreat of the continental ice sheets at the end of the last ice age resulted in the dissolution of hydrates, and initiated the formation of many conventional giant gas fields in or near present permafrost areas. By similar reasoning, marine regressions could release marine hydrates into conventional onshore gas deposits.

Resource Estimates

Resource estimates for gas hydrates are highly speculative due to incomplete knowledge of hydrate occurrences and poor methods of estimating reserves in known occurrences. Conventional methods of estimating gas resources are not applicable to hydrate-bearing formations because:

(1) on conventional well-logs, hydrates have the same characteristics as permafrost.

(2) flow tests require a means to disrupt equilibrium

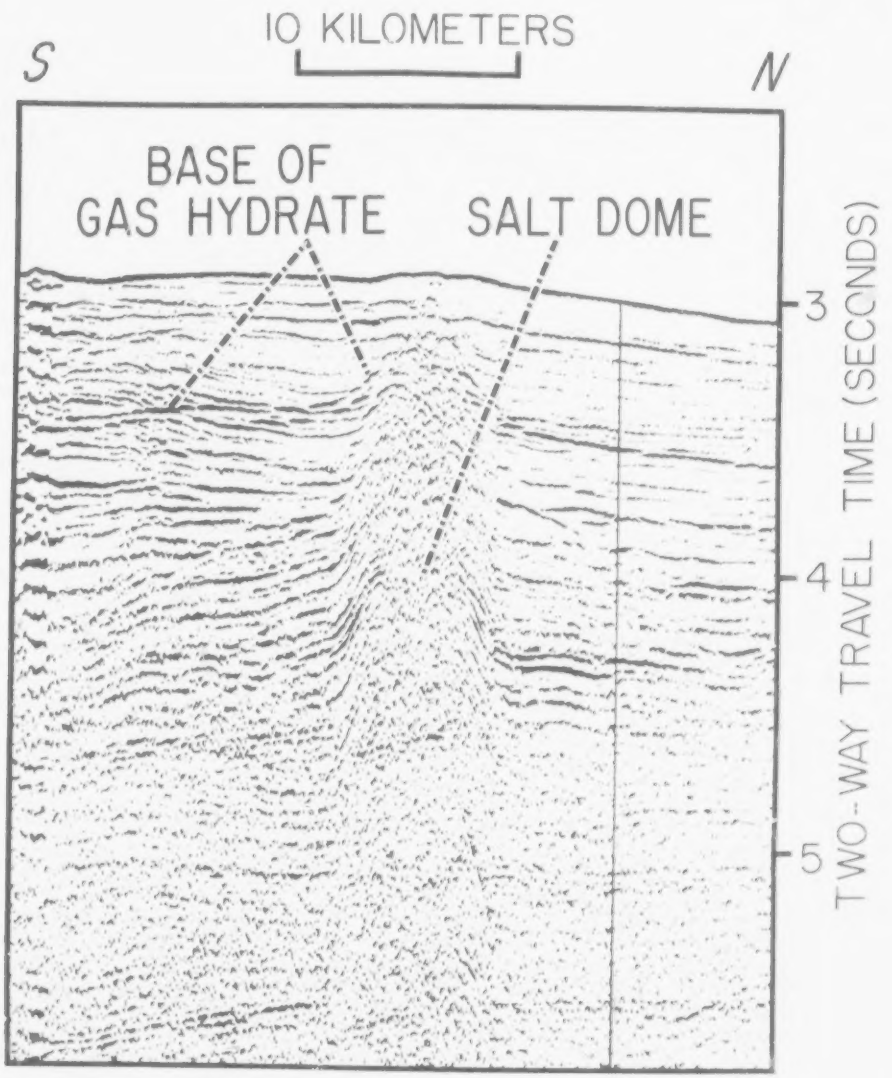

Figure 40 — Seismic profile showing gas hydrate accumulation flanking a salt dome (Dillon, et al., 1980)

conditions and dissolve the hydrates.
(3) reservoir permeability is very low.
(4) the hydrate gas/free gas ratio cannot be fully determined from core samples or porosity estimates (Barraclough, 1980).

Nevertheless, regional and world estimates of gas-hydrate resources have been calculated by several workers (table 37). Soviet scientists attempted to incorporate many complex factors into their calculations, including regional and world coefficients of present and past temperatures, sediment thicknesses, percent of organic interval in the sediments and percent methane production and conservation (Trofimuk, et al., 1977).

World estimates for gas-hydrate resources range from 500 to 1,200,000 Tcf for permafrost areas and from 110,000 to 270,000,000 Tcf for ocean sediments. Estimates show considerable variation, but submarine sediments seem to be a much greater resource for gas hydrates due to in-situ production of biogenic methane and the extensive nature of stable pressure/temperature conditions favorable for hydrate formation. Estimates by Dobrynin, et al. (1979) are considerably higher than others. They describe their calculations as "rough estimates" based on permafrost coverage and physical zones of hydrate stability in the world's oceans without apparent regard for distribution of sedimentary basins or availability of natural gas. Their estimates should be considered a very optimistic upper limit.

None of these estimates seem to account for reservoir quality. Proved and currently recoverable world resources of conventional natural gas are 2,329 to 2,594 Tcf, and estimated total remaining recoverable resources are 7,900 to 9,200 Tcf (Parent, 1980). If only 1% of gas-hydrate resources are within porous and permeable strata, then the most conservative estimate for recoverable gas hydrates is still over 1,100 Tcf, or half of our proved and currently recoverable conventional gas resources. Also, these estimates do not consider possibly significant accumulations of free gas beneath hydrate layers.

Estimates for gas hydrate resources in the United States (table 38) were extrapolated from world estimates (table 37). Based on Soviet estimates for gas hydrates in Siberia, McIver (1979) calculates that Russian sedimentary basins in permafrost areas contain an average of 280 million cubic feet per square mile. Sedimentary basins in permafrost areas of Alaska cover about 83,000 square miles. A United States equivalent to gas hydrate resources in the U.S.S.R. based on McIver's (1979) ratio amounts to about 23 Tcf. Ratios from world estimates indicate that U.S. gas-hydrate resources in permafrost areas may range from 11 to 25,000 Tcf. The U.S. Geological Survey sponsored a gas hydrate workshop in Menlo Park, California on July 16-17, 1979, which targeted the National Petroleum Reserve of Alaska as a potential gas-hydrate resource area which should be evaluated (Goodman, 1980).

Estimates for gas-hydrates in submarine sediments offshore from the United States are restricted to shelf areas since they represent approximate legal and technological boundaries. Dobrynin, et al. (1979) suggest that approximately 35% of all submarine gas hydrates occur in the shelf zone. Continental shelf and slope areas cover about 20 x 10^6 mi^2 of the world (Weeks, 1974). United States shelf and slope areas amount to about 1.4 x 10^6 mi^2 (Cram, 1971). Therefore, the gas-hydrate resources in continental shelf and slope areas of the U.S. represent about 7% of the total world resource x 35% (shelf factor).

Table 37 — World estimates of gas hydrate resources

Continental	Oceanic	Reference
m^3 (Tcf)	m^3 (Tcf)	
5.7 x 10^{13} (2010)	5-25 x 10^{15} (1.8-8.8 x 10^5)	Trofimuk, et al., 1977
3.1 x 10^{13} (1100)	3.1 x 10^{15} (1.1 x 10^5)	McIver, 1979; adapted from Chersky & Makogon, 1970
$\geq$ 1.4 x 10^{13} (500)	—	Meyer, 1979
3.4 x 10^{16} (1.2 x 10^6)	7.6 x 10^{15} (2.7 x 10^5)	Dobrynin, et al., 1979

Table 38 — Estimates of gas hydrate resources in the United States

Continental (Alaska) m^3 (Tcf)	Oceanic* m^3 (Tcf)	Adapted Reference
1.2×10^{12} (42)	$1.2\text{-}6.1 \times 10^{14}$ ($4.2\text{-}21 \times 10^3$)	Trofimuk, et al., 1977
6.5×10^{11} (23)	7.6×10^{13} (2.7×10^3)	McIver, 1979; Chersky and Makogon, 1970
$\geq 3.1 \times 10^{11}$ (11)	—	Meyer, 1979
7.1×10^{14} (2.5×10^4)	1.9×10^{17} (6.7×10^6)	Dobrynin, et al., 1979

*Continental shelf and slope estimate only. Assumes 35% of oceanic gas hydrate resource occurs in this zone.

Estimates for gas hydrates in submarine sediments along U.S. shelf areas range from 2,700 to 6,700,000 Tcf, a sizeable resource even at the most conservative estimates.

Gas-hydrate resources in the U.S. and the world seem to be quite significant. It must be emphasized, however, that present estimates are very highly speculative and a large amount of further study of this resource is necessary before quasi-reliable estimates can be obtained.

Production Technology

Problems associated with identification of gas hydrate accumulations are compounded by a lack of production technology. Production problems are founded in a poor understanding of the fundamental properties of gas hydrates as they occur in nature, such as formation and decomposition in a porous media. To date, only the Soviets claim production of significant volumes of natural gas from permafrost deposits (Makogon, et al., 1971; Cieslewicz, 1971; Makogon, 1974). No reports of offshore production of gas hydrates have been issued.

Hydrated gas densities are too low for economic "mining" of the resource, so in-situ conversion of solid methane hydrate to free natural gas is the only feasible alternative. There are three main methods of hydrate dissolution:

(1) Pressure reduction
(2) Temperature increase
(3) Catalytic dissolution

In theory, Holder, et al. (SPE/DOE 8929, 1980) predict that with 60% energy efficiency and 90% gas recovery, the majority of gas-hydrate occurrences could be recovered with a net energy gain. However, many unsolved problems remain.

Injection or withdrawal of fluids to lower pressure, raise temperature or dissolve hydrates is time-consuming and difficult due to the very low permeability of hydrate-cemented sediments. All methods will require some form of stimulation such as hydraulic fracturing. The Soviets claim success at the Messoyukha field by injecting a freezing-point depressant, methyl alcohol, to dissolve the hydrates (Dobrynin, et al., 1979). However, the Soviets are extracting free gas as well as hydrated gas from the reservoir and they indicate that their operation is profitable only if gas hydrates occupy less than 10% of the pore space (with greater than 90% of the pores filled with free gas). It would seem that too much hydrated gas in pore spaces results in permeabilities which are too low for economic extraction. In addition to permeability problems, inhibitors such as methyl alcohol are costly, toxic, difficult to regenerate and highly volatile.

Temperature elevation is also costly and very slow due to permeability problems. This method might prove economic, however, in regions where hydrothermal fluids or deep brines are readily available as a heat source.

Additional problems associated with gas-hydrate production include large volumes of water which are released during hydrate decomposition. Also, for drilling through gas hydrates to underlying free gas reservoirs, casing seals with hydrate-cemented sediments are vulnerable to channeling and washout associated with hydrate decomposition (Bily and Dick, 1974; Goodman, 1980). Conventional coring methods are not feasible for hydrate-cemented sediments since pressure buildups during hydrate decomposition can result in core barrel explosions (Goodman, 1980). Drilling techniques in permafrost areas are discussed in more detail by Goodman (1978).

Other problems unique to the development of gas hydrates in submarine sediments include the difficulties of deep-water drilling and production, since hydrates are the primary sediment cement in otherwise unconsolidated sediments.

Present technology would indicate that production of free gas trapped beneath or in association with hydrate layers would be more feasible than the production directly from hydrates. Any decrease of pressure in free-gas reservoirs would result in further decomposition of the overlying hydrate layer to maintain reservoir pressure. In this manner, the hydrates might be indirectly produced.

The Gas Research Institute held a gas hydrate workshop in Denver on February 1, 1979, at which a consensus of information indicated that U.S. gas hydrate resources are largely undetermined and that development of feasible production techniques must be established (Goodman, 1980).

Obstacles to Commercialization

Major technological obstacles have prevented development of gas-hydrate resources and will continue to hinder development in the foreseeable future. Initial exploitation of gas-hydrate deposits may be restricted to production of free gas beneath hydrate layers.

Exploration and development of gas hydrates is being hindered by legal obstacles. Many permafrost areas in Alaska which may contain gas-hydrate resources are restricted from development by designation of wilderness areas and similar withdrawals by RARE II designations. Ownership of gas-hydrate resources in ocean areas beyond national boundaries has not been established by international law.

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PART III

REVIEW OF POTENTIAL CONVENTIONAL RESOURCES OF NATURAL GAS IN CANADA

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PART III. REVIEW OF POTENTIAL CONVENTIONAL RESOURCES OF NATURAL GAS IN CANADA

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REVIEW OF POTENTIAL CONVENTIONAL RESOURCES OF NATURAL GAS IN CANADA*

The Geological Survey of Canada has recently provided the following estimates of ultimately recoverable quantities of marketable natural gas in Canada. These are presented in four regions: Western Canada, the East Coast, the Mackenzie Delta-Beaufort Sea, and the Arctic Islands. The ultimately recoverable quantities for all of Canada are thought to be 420 trillion cubic feet (Tcf) on an average expectation (40 percent probability) and 581 Tcf on a highly speculative basis (5 percent probability). Almost 100 Tcf of gas have been found in Western Canada, possibly 4 Tcf in the East Coast, about 10 Tcf in the Mackenzie Delta-Beaufort, and 12 to 20 Tcf in the Arctic Islands. Proved and produced gas amounts to about 126 Tcf. Therefore, the average expectation for future gas potential in Canada is about 300 Tcf.

WESTERN CANADA BASIN

This region consists of the western Canada sedimentary basin in the provinces of Manitoba, Saskatchewan, Alberta and British Columbia. It extends from the Precambrian shield on the east to the Rocky Mountains on the west, south of 60° latitude, and is in a mature stage of exploration. Exploration to date has led to the discovery of more than 9,000 gas pools and over 3,200 oil pools. With the exception of the Disturbed Belt, the vast majority of these pools are stratigraphically controlled and the analysis of some 65 plays throughout the basin indicates that this trend will probably continue. Nonconventional gas reported in relatively tight rocks in the deep basin in western Alberta is excluded from these estimates.

Potential Evaluation

The relatively mature state of exploration is reflected in the estimates. The character of the resource probability curve (fig. 41) leaves a narrow range in the possible values for potential. For Western Canada, the estimate curves include major reserves plus potential. Thus the average expectation of 159 Tcf on the gas curve is made up of existing reserves of nearly 100 Tcf, plus about 62 Tcf of potential resource. At highly speculative levels, the undiscovered gas could be as high as 100 Tcf.

EAST COAST

The estimates of oil and gas resources for this region cover the area extending from the Scotia Shelf into the Baffin Bay basin. More than 125 exploratory wells have been drilled in this region since 1966 (fig. 42). This has resulted in the recognition of a major gas province near Sable Island and a narrow, dominantly gas, province extending along the coast of Labrador and probably into Baffin Bay. The estimates are based on the analysis of 32 plays primarily in the sedimentary wedge of Tertiary and Mesozoic age that thickens off the continental shelf. Important trap types include: salt-cored diapiric features, large roll-over faults, and fault blocks with overlying and flanking sands, as well as a multitude of stratigraphic traps involving carbonate and clastic pinch outs and erosional surfaces. Clastic sediments are generally deltaic, and, with the exception of the Hibernia area, contain organic material that is dominantly land-derived plant detritus. This, coupled with the relative geochemical immaturity, indicates the possibility that the East Coast will be dominantly a gas-prone region.

*Review prepared by Donald W. Axford, D. W. Axford & Associates Ltd., and A. A. Wilkins, TransCanada PipeLines, Canadian observers to the Potential Gas Committee. Source: Procter, R. M., Lee, P. J., and Skibo, D. N., March 1981, Canada's Conventional Oil and Gas Resources: Geological Survey of Canada Open-File Release No. 767.

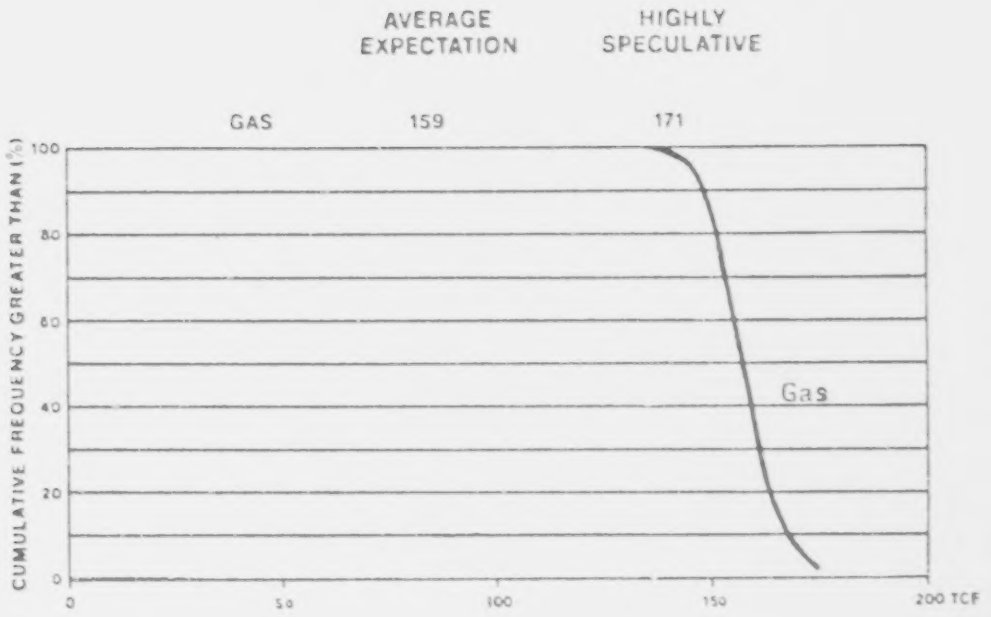

Figure 41 — Western Canada gas resources cumulative probability curve

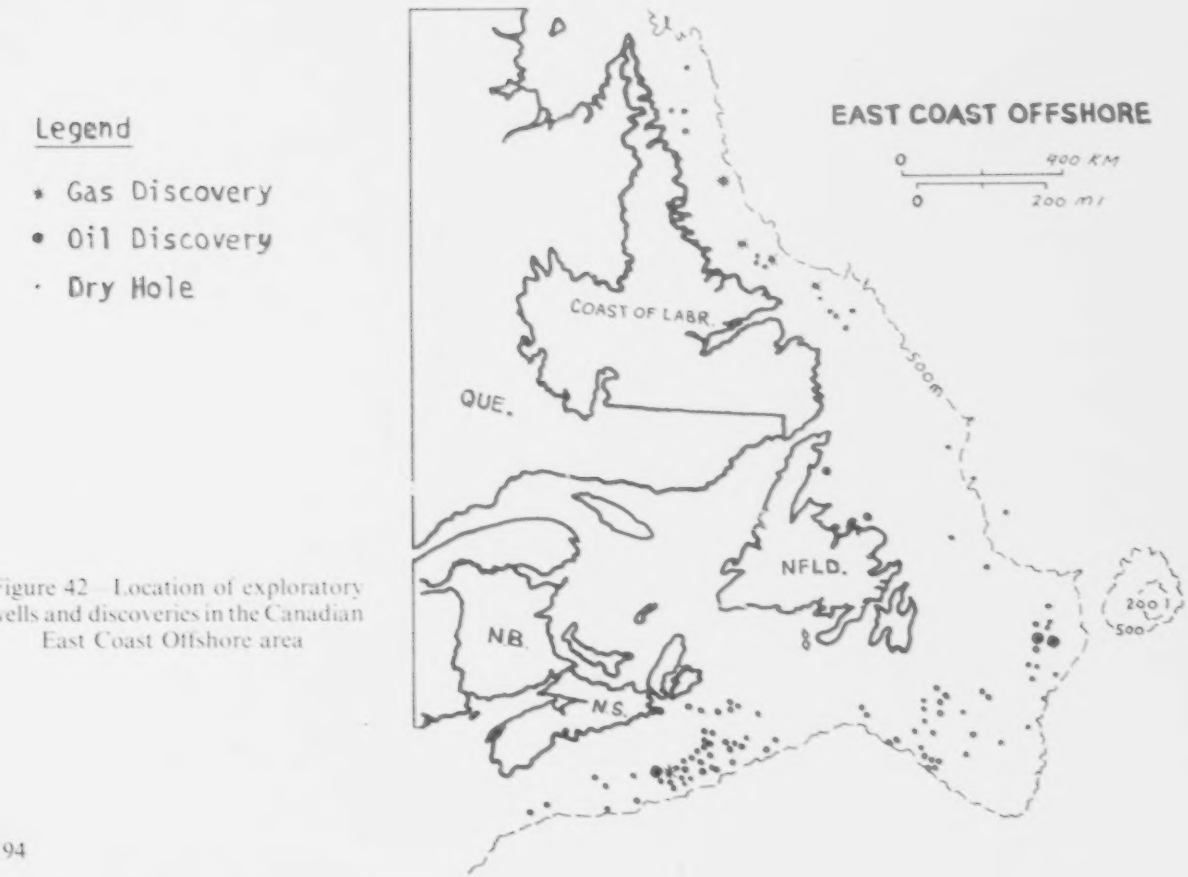

Figure 42 — Location of exploratory wells and discoveries in the Canadian East Coast Offshore area

Potential Evaluation

The estimates of potential resources indicate an average expectation of approximately 72 Tcf of gas for the East Coast region and highly speculative potential for as much as 125 Tcf (fig. 43). No estimates of proved reserves are available at this time; however, commercial quantities of gas, probably exceeding one trillion cubic feet, exist at the Venture discovery. Individual discoveries along the Labrador coast, although exciting, are possibly too small to be economic at this time.

MACKENZIE DELTA-BEAUFORT SEA

This region includes the onshore part of the Mackenzie Delta and that part of the offshore extending to the edge of the continental shelf at a water depth of approximately 600 feet. It also extends from the Amundsen Gulf west to the Canada–Alaska boundary. The region is underlain by deltaic sandstones and shales of Mesozoic and Tertiary age which thicken rapidly northward to more than 40,000 feet a short distance seaward from the present delta. These clastics overlie faulted Paleozoic rocks which step down steeply beneath the Mesozoic-Tertiary cover. The Tertiary sequences contain the most important sandstone reservoirs, but additional reservoir rocks are present in both Cretaceous and Jurassic sands.

Major targets have been the diapiric structures formed by mud flow at depth, some of which attain great magnitude and or linearity. Other targets result from closure provided by roll-over and growth faults, sometimes coupled with plastic deformation at depth. The main emphasis on drilling started on Richards Island near shore and then extended into the offshore region through the use of artificial islands. The targets are deltaic sands of the present and ancestral Mackenzie Delta. More recently, exploration has extended to the deeper Beaufort Sea region where drill-ships now test sedimentary wedges which were deposited in deeper water beyond the edges of ancient continental shelves. Parts of the region such as the area extending west to the Alaska boundary have received very little exploratory effort (fig. 44).

Geochemically the region can be characterized as thermally immature, with hydrocarbons derived from source rocks containing dominantly land-derived

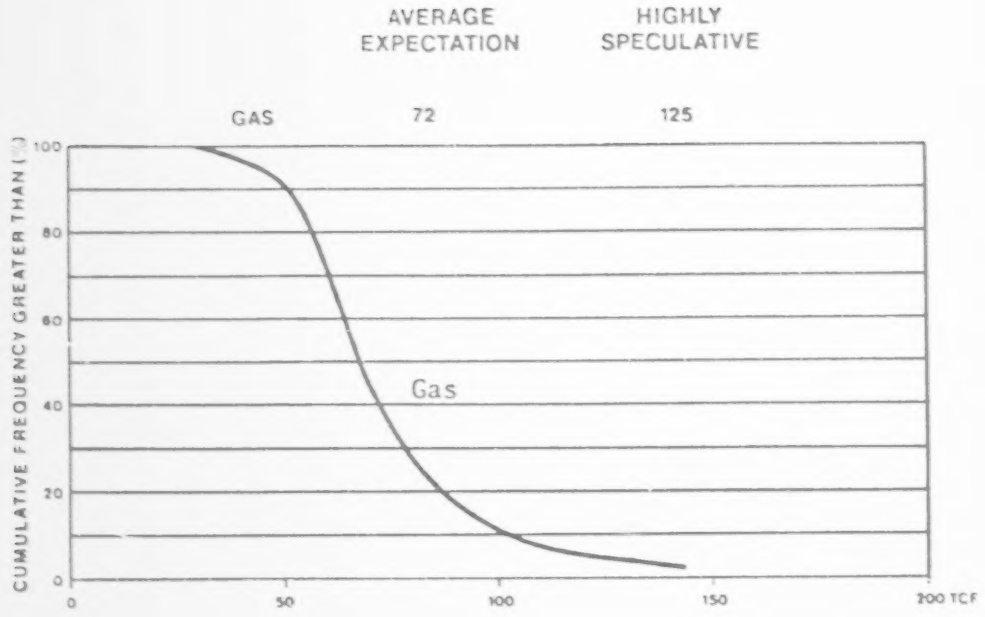

Figure 43 — East Coast gas resources — cumulative probability curve

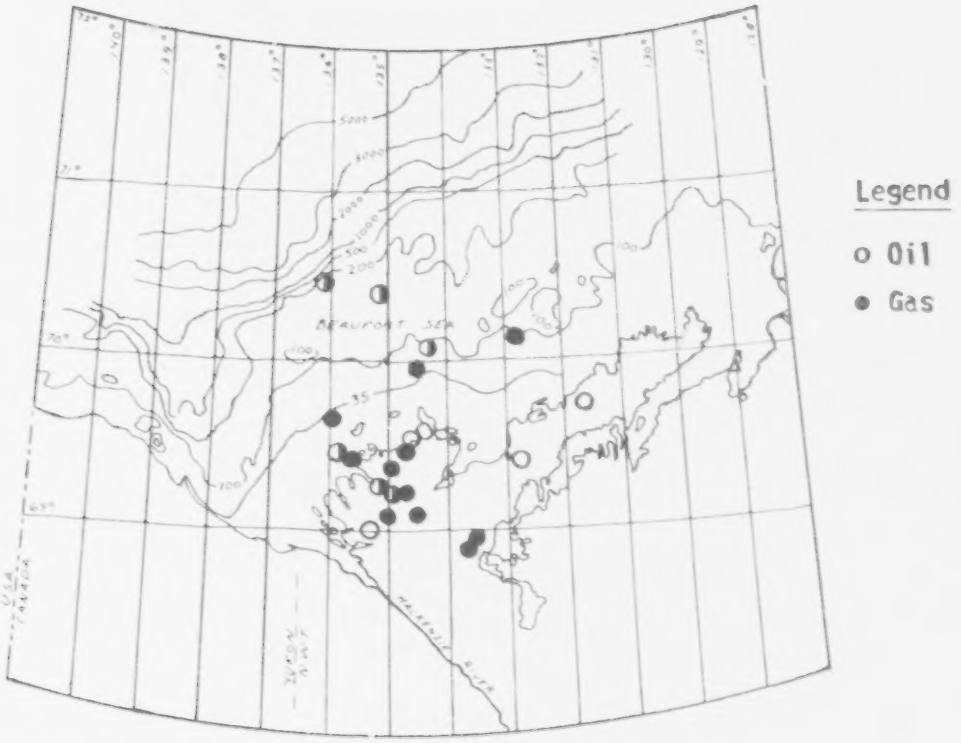

Figure 44 — Map of Mackenzie Delta-Beaufort Sea region showing location of oil and gas discoveries

plant material. These characteristics are inconsistent with the observed occurrences of liquid hydrocarbons and condensates. Current thinking is that an unusual concentration of resins derived from forests and capable of conversion to liquid hydrocarbons at relatively low temperatures may explain the geochemical enigma. As indicated by the estimate curves, the region is dominantly gas-prone but is also thought to contain more oil than any of the other frontier regions.

Potential Evaluation

In preparing the estimate of resources, 17 exploration plays have been assessed. The average expectation is 112 Tcf of gas. In the highly speculative range, these estimates extend to 147 Tcf (fig. 45). Estimates of discovered reserves are almost as speculative as those of undiscovered potential; however, without including Dome's recent activities in the Beaufort Sea, there is fair agreement that at least 6 Tcf of gas have been discovered — primarily in the Richards Island area. A more optimistic view would indicate there could be as much as 10 Tcf.

ARCTIC ISLANDS

The Arctic Islands region represents one of the most diverse areas for petroleum accumulation. Exploratory drilling began in 1961 in this large area, but half of which is covered by water. Since then, more than 140 exploratory wells have been drilled (fig. 46). Although exploration opportunities exist in rocks from the Precambrian through Mesozoic, by far the greatest activity has been focused on rocks of Jurassic age. This effort has resulted in discovery of two, and possible three, giant gas fields, as well as others in the one trillion cubic foot range, with total discoveries probably exceeding 15 Tcf of gas. Although there are indications that oil will occur in parts of the area in a variety of plays, evidence to date suggests that the Arctic Islands region will be dominantly a gas province. This situation reflects the basic geochemistry of the region, in which Mesozoic rocks are primarily immature with high concentration of land-derived organic material. Lower Paleozoic rocks, although having more oily source materials, have passed beyond the maturity level and now contain mainly gas.

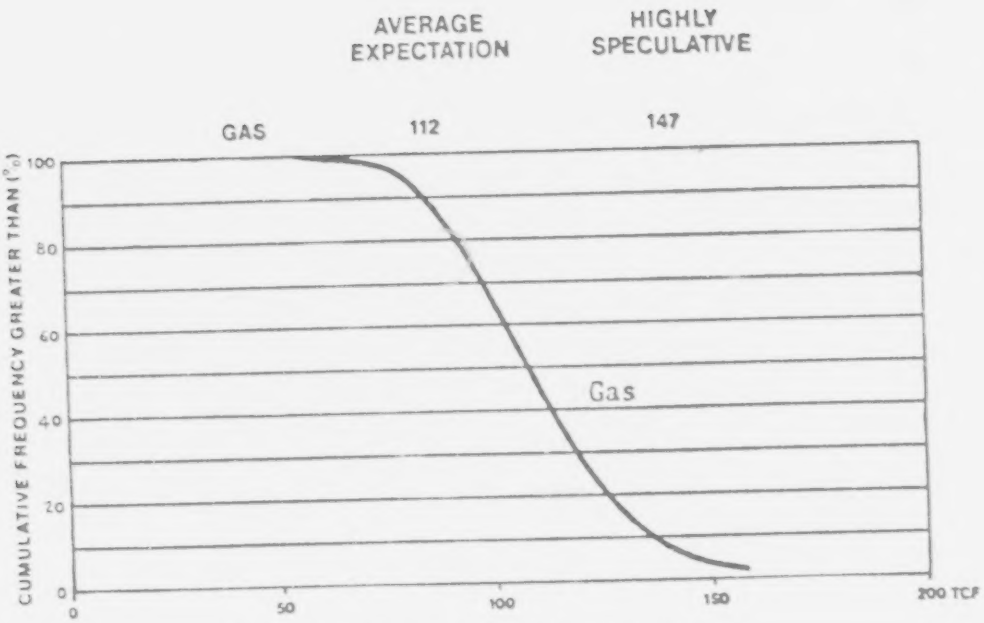

Figure 45 — Mackenzie-Beaufort gas resources cumulative probability curve

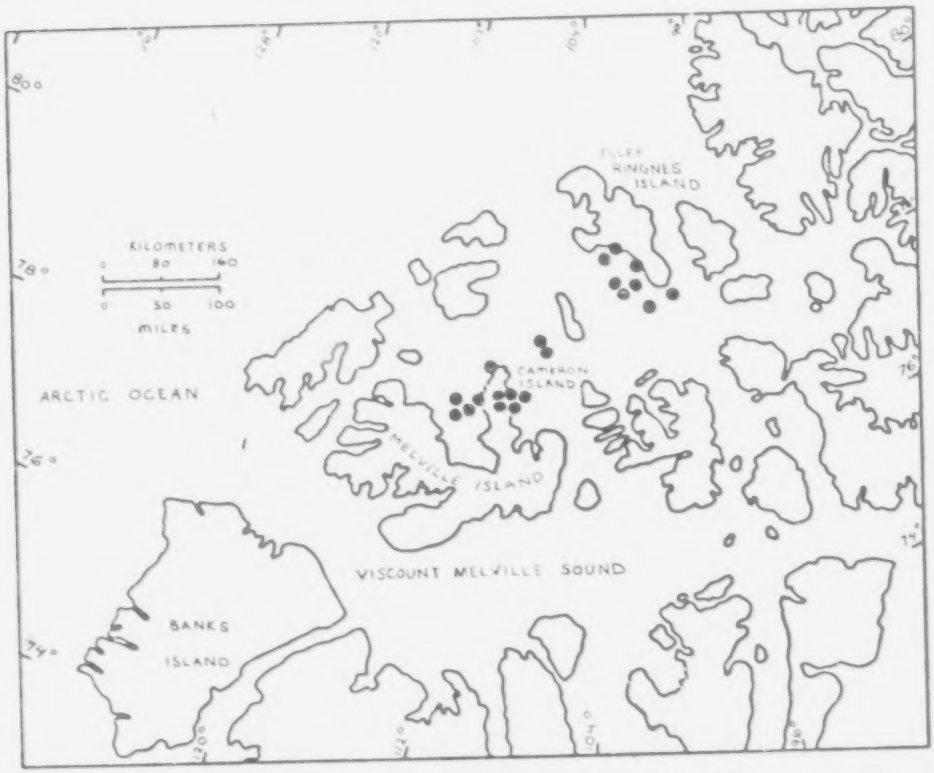

Figure 46 — Arctic Islands hydrocarbon potential assessment area

Potential Evaluation

The current estimates of resources for this region include an average expectation of 87 Tcf of gas. At highly speculative levels, there could be 138 Tcf of gas (fig. 47). These estimates include an established reserve which probably ranges from a minimum of 12 Tcf and which, with effective delineation drilling, may prove to be larger than 20 Tcf. The estimates are the result of the analysis of 27 exploratory plays. Many of these have yet to be tested, so this introduces a large element of uncertainty and this is reflected in the distribution of estimates of potential.

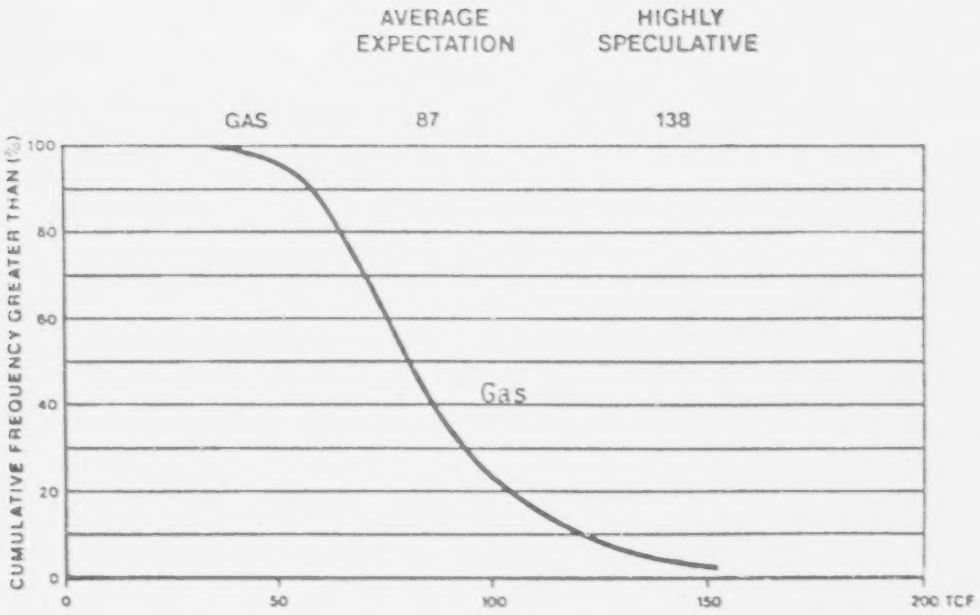

Figure 47 — Arctic Islands gas resources cumulative probability curve

PART IV

POLICY GUIDELINES AND MEMBERSHIP OF THE POTENTIAL GAS AGENCY AND THE POTENTIAL GAS COMMITTEE

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POLICY GUIDELINES AND MEMBERSHIP OF THE POTENTIAL GAS AGENCY AND THE POTENTIAL GAS COMMITTEE

GENERAL POLICY STATEMENT

An appraisal of the long-range prospects of the natural gas industry in the United States — an appraisal that is useful for financial, managerial, and government purposes — requires, as an essential element, scientific, authoritative, and objective estimation of the potential supply of natural gas which may become available to the nation in addition to currently available proved recoverable reserves of natural gas. The Committee on Natural Gas Reserves of the American Gas Association, an industry committee, is fulfilling part of the need for information for future planning by providing periodic estimates of proved recoverable reserves of natural gas immediately available to the industry.

The Potential Gas Committee fulfills the remainder of this requirement by providing periodic estimates of the potential supply of natural gas which may become available. This Committee, together with its several Area Work Committees, is comprised of about one hundred fifty individuals from the production, transmission, and distribution segments of the natural gas industry who are knowledgeable with respect to the potential supply of natural gas.

The quantities of natural gas included in this report by the Potential Gas Committee are only those which are considered to be recoverable by technology currently available or feasible in the foreseeable future. There are additional, potentially recoverable, quantities of natural gas contained in such situations as gaseous coal seams, geopressured zones, certain brown shales, sandstones with very low permeability, and gas hydrates. Some workers have postulated large quantities of recoverable natural gas from each of these nonconventional sources, but there still remains considerable question as to the reasonable order of magnitude and the recoverability of this gas. These nonconventional sources largely have not been considered at this time by the Potential Gas Committee because the Committee feels that the technology of recovery has not yet been adequately demonstrated. As technological developments occur, the Committee will further study the potential from these sources and reconsider its estimates.

The Potential Gas Committee and its Area Work Committees discuss matters and data that are confidential. Fulfillment of the objectives of the Potential Gas Committee cannot be realized without the availability and utilization of information of a highly confidential nature. It is, therefore, the policy of the Potential Gas Committee and its Work Committees that every member, observer, and representative will respect such information and that there will be no disclosure of information or estimates, discussions, or other data, except as approved for release by the Potential Gas Committee.

A diagram of the organizational structure for the estimation of the potential supply of natural gas is shown in figure 48. A detailed description of the membership and duties of the several committees and of the Potential Gas Agency is presented in the sections which follow.

MEMBERSHIP OF COMMITTEES AND POLICY GUIDELINES FOR COMMITTEES

Gas Supply Committee of the American Gas Association

The membership of the Gas Supply Committee consists of representatives of member companies of the American Gas Association selected by the Chairman of the Board and approved by the Board of Directors of the American Gas Association.

GAS SUPPLY COMMITTEE
American Gas Association
W. J. Bowen, Chairman
Robert B. Kalisch, Staff Executive
Objectives, policy agency selection, financing, industry liaison.

POTENTIAL GAS AGENCY
Colorado School of Mines
Mineral Resources Institute
Supported by the American Gas Association
Harry C. Kent, Director
Approve criteria and methods, insure maintenance of standards and objectivity, review and evaluate reports, publish final estimate of potential gas.

POTENTIAL GAS COMMITTEE
George C. Grow, Jr., Chairman
Merlin A. Johnson, Secretary
E. Floyd Humphries, Chairman, Executive Committee
Charles L. Neumeyer, Chairman, Editorial Committee
Robert J. Cordell, Chairman, Committee on Definitions and Procedures
Richard J. Burgess, Chairman, Time and Site Committee

Under direction of Potential Gas Agency, outline study, establish criteria and methods, designate and instruct Work Committees, supervise, coordinate and compile estimates made by Work Committees.

Membership
(a) Chairman and Regional Vice Chairmen — appointed by Potential Gas Agency and approved by A.G.A. Gas Supply Committee.
(b) Each Work Committee Chairman.
(c) Department of Energy, Energy Information Administration, Federal Energy Regulatory Commission, Department of Interior Geological Survey, Bureau of Mines, NARUC, IOCC, and such other governmental agencies as the Gas Supply Committee and Potential Gas Agency shall approve — one non-voting observer each, and alternates, if desired.
(d) Potential Gas Agency — Director — Ex officio.
(e) Honorary technical advisors and members-at-large.
(f) Gas Research Institute and Institute of Gas Technology — one non-voting observer each, and alternates, if desired.
(g) Canadian and Mexican natural gas industry — one non-voting observer each, and alternates, if desired.
(h) A.G.A., staff — one non-voting observer.
(i) One Pipeline and one Distributor representative to be designated by the Gas Supply Committee.
(j) Others appointed by Gas Supply Committee and approved by Potential Gas Agency.

REGIONAL VICE CHAIRMEN AND AREA WORK COMMITTEES

Number of committees and assignments as designated by Potential Gas Committee and approved by Potential Gas Agency.

Under direction of Potential Gas Committee, prepare estimates for given assignment.

Membership
(a) Chairman — appointed by Chairman of Potential Gas Committee and approved by Potential Gas Agency.
(b) Sufficient producer and other qualified members to insure proper representation for given assignment — appointed by Chairman of Work Area.
(c) At least one Pipeline and one Distributor representative to be designated by Gas Supply Committee.

WESTERN REGION
Charles J. Crowley, Chairman

Area	Chairman
H	James A. Barlow, Jr.
I	Robert D. Habbit
K	Alexander Sisson
L	William F. Edmondson

CENTRAL REGION
James K. Curry, Chairman

Area	Chairman
C	William E. Mantek
D	Paul Mounce
J-N	Alan F. Chatfield
J-S	Charles M. Allen

EASTERN REGION
Robert W. Gallagher, Chairman

Area	Chairman
A	E. Perry Bendler
B	Billy C. Cook
E	Charles R. Brammell
G	Jeffery V. Morris

Figure 48 Organization of Potential Gas Supply Studies

The scope of the committee is to coordinate, motivate, and make recommendations to the Board of American Gas Association as to the areas in which A.G.A. should become more active in the development of adequate gas supply for both short-term and long-term. In addition, the committee undertakes special projects, where necessary, to evaluate industry gas supply programs. The Gas Supply Committee oversees the work of the Potential Gas Agency.

The primary duties and responsibilities of the Gas Supply Committee with relation to potential gas studies include the following:

a. Establishing policy and objective.
b. Providing required financial support.
c. Maintaining liaison with industry and industry organizations.
d. Selecting the Potential Gas Agency.
e. Approving the appointment of the chairman and vice chairman of the Potential Gas Committee by the Potential Gas Agency.
f. Appointing pipeline and distributor representatives to the Potential Gas Committee and to each Area Work Committee.
g. Appointing such other members and observers to the Potential Gas Committee as may be necessary or advisable.
h. Assisting in procurement of qualified manpower to staff properly the Potential Gas Committee and the Area Work Committees.

The Gas Supply Committee of the American Gas Association takes no part in the work or the deliberations of the Potential Gas Committee or its sub-committees. The Gas Supply Committee does not participate in the studies leading to the estimates of potential supply of natural gas, and it neither approves nor disapproves the definitions and procedures, the estimates, or the report.

Potential Gas Agency of the Colorado School of Mines

The Potential Gas Agency is supported by the American Gas Association. The American Gas Association is free, however, to take independent views of the operations of the studies produced by the Agency and its committees.

The Potential Gas Agency includes the following:

a. A director, appointed by and responsible to the Colorado School of Mines.
b. Such additional staff personnel as may be required.
c. Members of the faculty of the Colorado School of Mines or other qualified individuals who may, from time to time, provide such professional services as the director of the Potential Gas Agency and the chairman of the Potential Gas Committee may determine necessary or desirable for discharging the duties of the Potential Gas Agency and the Potential Gas Committee.

The primary duties and responsibilities of the Potential Gas Agency include the following:

a. Approving criteria and methods established by Potential Gas Committee, including protecting the confidentiality of Potential Gas Committee data.
b. Insuring maintenance of the highest scientific standards and objectivity in Potential Gas Committee studies and reports.
c. Reviewing and evaluating reports prepared by the Potential Gas Committee.
d. Publishing, distributing, and publicizing reports of final estimates and other pertinent reports prepared by the Potential Gas Committee so as to assure the widest possible distribution and to promote understanding of them.
e. Further develop mutual understanding among the segments of the gas industry by helping the Gas Supply Committee unite the industry behind the potential gas studies.
f. Help improve industry-government relations in the public interest looking toward maximum acceptance and usefulness of potential gas studies.
g. Fulfill the professional obligation to publish technical papers concerning new techniques and knowledge gained.
h. Appointing chairman and vice chairmen of Potential Gas Committee, with approval of Gas Supply Committee.
i. Approving appointment by Gas Supply Committee of other members, representatives and observers to the Potential Gas Committee.
j. Approving appointment by chairman of Potential Gas Committee of chairman of each Area Work Committee and chairmen of other committees.
k. Conduct the work of the Potential Gas Agency, in the public interests, in a manner which will enhance the stature of the Colorado School of Mines.
l. Adhere to the highest standards of objectivity.

The Colorado School of Mines may pursue other research, and individuals from the Agency may be involved in other research, consulting, and preparation and publication of papers in their professional fields, so long as these activities do not involve a conflict of interest nor invalidate the objectivity of the Agency.

Potential Gas Committee

Membership of the Potential Gas Committee includes the following:

a. Chairman of Potential Gas Committee.
b. Secretary of Potential Gas Committee.
c. Regional vice chairmen.
d. Chairman of each Area Work Committee.

e. Chairman of Executive Committee.
f. Chairman of Editorial Committee.
g. Chairman of Committee on Definitions and Procedures.
h. Chairman of Time and Site Committee.
i. Director of the Potential Gas Agency, ex officio.
j. Observer from the Federal Energy Regulatory Commission.
k. Observers from the Department of Energy.
l. Observer from the Geological Survey, United States Department of the Interior.
m. Observer from the Bureau of Mines, United States Department of the Interior.
n. Observer from National Association of Regulatory Utility Commissioners.
o. Observer from the Interstate Oil Compact Commission.
p. Observer from the Gas Research Institute.
q. Observer from the Institute of Gas Technology.
r. Representative from the natural gas pipeline industry.
s. Representative from the natural gas distribution industry.
t. Observer representing the American Gas Association.
u. Observer from the Canadian natural gas industry and observer from the Mexican natural gas industry.
v. Honorary Technical Advisors.
w. Members-at-large.
x. Representatives and observers from other organizations may be recommended for appointment by the Potential Gas Agency Director and approved by the Gas Supply Committee.

All members of the Potential Gas Committee, except those specifically designated as observers, are considered as voting members of the Potential Gas Committee. Observers are invited and encouraged to participate in discussion of items brought before the Potential Gas Committee but do not have a vote in the determination of policy and procedure. Alternates to representatives and observers may be appointed.

Candidates for committee chairmen and vice chairmen normally will be geologists or persons with geology background from the academic community, pipelines, independent firms, gas utilities or producing companies. Retired or semi-retired gas industry people are not excluded from consideration.

Officers of the Potential Gas Committee and Work Area Committees are appointed as outlined in the Organizational Chart (fig. 48). Normally they serve for a period of one report. They are eligible for reappointment, however, for one additional report period. In calculating eligibility for reappointment, a partial term of office shall not be counted. This policy shall not operate to disqualify a member from longer service by reason of elevation in the organization. In other words, the two-term limitation shall apply to each position held, considering each membership or officership on a work committee or top committee as a separate position.

All officers, regional chairmen, and the pipeline and distributor representatives appointed by the American Gas Association Gas Supply Committee shall be subject to the two-report limit. Exceptions must be recommended by the appropriate Committee Chairman and the Potential Gas Agency Director, and approved by the American Gas Association Gas Supply Committee.

The designation of Honorary Technical Advisor may be given to such persons as have performed exceptional service to the Potential Gas Committee and whose continued participation and advice are desirable for the continued successful operation of the Committee. Honorary Technical Advisors are permanent voting members, and their appointment is recommended by the Executive Committee and approved by the Potential Gas Agency Director and the Gas Supply Committee.

Members-at-large include persons who have special knowledge of the occurrence of natural gas or the natural gas industry, and whose expert advice will contribute to the successful performance of the Committee's assignments. The appointment of members-at-large is approved by the Gas Supply Committee upon recommendation by the Potential Gas Agency Director. Members-at-large are appointed for the preparation of a specific PGC report. Their appointment may be continued indefinitely but is subject to review and approval at the time of organization of the Potential Gas Committee for each succeeding report.

Observers from sponsoring associations, governmental agencies, and other cooperating groups serve at the discretion of these organizations and are not subject to the two-report policy.

The primary duties and responsibilities of the Potential Gas Committee include the following:

a. Outlining the scope and coverage of the estimates of potential natural gas supply.
b. Establishing criteria and methods for estimation of potential natural gas supply and other pertinent studies.
c. Designating Work Areas and Special Projects.
d. Appointing the chairman of each Area Work Committee (by action of chairman of Potential Gas Committee).
e. Approving appointment of other members of each Area Work Committee who are appointed by the chairman of each Area Work Committee (by action of chairman of Potential Gas Committee).

f. Instructing Area Work Committees.
g. Supervising, coordinating, advising, reviewing, evaluating, approving, and compiling estimates and such other assignments as may be given to committees.
h. Preparing reports of final estimates and such other reports as may be pertinent.
i. Submitting reports of final estimates and other pertinent reports to the Potential Gas Agency and counseling with director regarding publication and distribution of such reports.

Area Work Committees

Membership of Area Work Committees includes the following:

a. Chairman of each Area Work Committee.
b. An appropriate number of qualified working members deemed necessary by the chairman of each Work Committee to insure the most objective estimates of potential supply of natural gas in the respective area assigned. Work Committee members are individuals from the natural gas and oil industries and other individuals who are qualified by their knowledge and experience to make estimates of potential supply of natural gas. The individuals are selected for each area because they have a close, working knowledge in all aspects of natural gas exploration and production.
c. At least one qualified representative on each Area Work Committee from the natural gas pipeline industry, appointed by the Gas Supply Committee.
d. At least one qualified representative on each Area Work Committee from the natural gas distribution industry, appointed by the Gas Supply Committee.

The Chairman and Vice Chairman of each Area Work Committee are subject to the two-report limit. Exceptions must be recommended by the Regional Vice Chairman, approved by the Potential Gas Committee Chairman and the Potential Gas Agency Director, and reported to the Gas Supply Committee, and only after receiving a clearance letter from the member's employer.

Other members of the Area Work Committees, appointed by the Area Chairman, will normally participate in the preparation of two successive reports. Service beyond the preparation of two reports may be continued if necessary to maintain adequate expertise and continuity on the Area Work Committee. Continuation of service beyond two reports must be recommended by the Area Chairman and approved by the Regional Vice Chairman, the Potential Gas Committee Chairman, and the Potential Gas Agency Director.

The primary duties and responsibilities of Area Work Committees include the following:

a. Appointing appropriate number of qualified working members to insure proper representation of various sectors of the industry and objectivity for the best estimates of potential supply of natural gas for the assigned areas (by action of chairman of each Area Work Committee).
b. Estimating quantity of potential supply of natural gas in working areas designated by the Potential Gas Committee pursuant to the guidelines and parameters established by the Potential Gas Committee and approved by the Potential Gas Agency, and such other studies as may be assigned by the Potential Gas Committee.
c. Performing such other assignments as may be made in the respective area assigned by the Potential Gas Committee regarding such estimate.

Each member of each Area Work Committee will submit his estimates of potential supply of natural gas and such other assignments as may be given to him in his assigned sub-area to the chairman and other members of his committee for review, evaluation, and approval.

Since the type and quantity of available information upon which to base estimates of potential natural gas supply vary widely from area to area, the Area Work Committee members use varied approaches in making their estimates. Inasmuch as the individual members work with private information obtained on a confidential basis from many sources, their working papers are not revealed in detail to anyone, including other members of the same Area Work Committee or others in the Potential Gas Committee. Without such confidential information the Potential Gas Committee could not perform its task; therefore, each member, observer, or representative of the Work Committees is aware of and must respect the confidential nature of the data made available to him and of the estimates and other assignments prepared or reviewed by the Area Work Committees and the Potential Gas Committee.

STANDING COMMITTEES OF THE POTENTIAL GAS COMMITTEE

Executive Committee

The Executive Committee shall serve as the administrative coordinating committee for the Potential Gas Committee. It shall consider and discuss any matters of policy which are brought to its attention and shall make recommendations to the Potential Gas Committee regarding changes in policy. It shall act in behalf of

the Potential Gas Committee on matters of urgency which arise between regularly scheduled meetings of the Potential Gas Committee. It may also be empowered to act on behalf of the Potential Gas Committee on matters designated by the Potential Gas Committee. At such times as vacancies occur in the following offices, the Executive Committee shall either act as a nominating committee to recommend suitable candidates or appoint a nominating committee from among its membership: PGC Chairman, Regional Vice Chairmen, Secretary of the PGC, and Chairman of the Executive Committee. Chairmen of PGC standing committees, with the exception of the Executive Committee, will be appointed by the PGC Chairman, subject to approval by the Executive Committee. All actions of the Executive Committee will be reported to the membership of the Potential Gas Committee at their next regularly scheduled meeting, and shall be subject to review and approval by the Potential Gas Committee.

Membership

Chairman, elected from the membership of the Potential Gas Committee by the voting members of the PGC at a regular meeting. Nominations for Chairman will be made by the Executive Committee and nominations will also be received from the floor. Normally, the Chairman will be elected at the fall meeting following publication of the biennial PGC report and will serve for two years. Vacancies will be filled by election at the next regular PGC meeting, following the same procedure, and a Chairman so elected will serve for the remainder of the unexpired term. In the absence of the elected Chairman, the Chairman of the Potential Gas Committee will serve as Chairman of the Executive Committee.

The following ex officio voting members: PGC Chairman, PGC Regional Vice Chairmen, Secretary of the PGC, Potential Gas Agency Director, Chairmen of Standing Committees, representatives appointed to the PGC from the natural-gas pipeline and natural-gas distribution industries, representative from the Canadian gas industry, observer from the American Gas Association.

In addition, a maximum of 5 voting members-at-large may be appointed by the Potential Gas Committee Chairman, subject to approval by the Potential Gas Agency Director.

Editorial Committee

The Editorial Committee will review and approve the editorial content and format of PGC reports. They will work closely with the Potential Gas Agency in the publication of all official publications of the Potential Gas Committee.

Membership

Chairman, appointed by the Potential Gas Committee Chairman, and approved by the Executive Committee. Four members of the Potential Gas Committee, appointed by the Editorial Committee Chairman, with approval of the PGC Chairman. PGC Chairman, ex officio; Potential Gas Agency Director, ex officio.

Committee on Definitions and Procedures

This Committee has the responsibility of reviewing and recommending to the membership of the Potential Gas Committee any proposed changes in the definitions and procedures used in the estimation of potential gas resources. Proposals to be reviewed by this Committee may be submitted by any member of the Potential Gas Committee. The Committee will further review estimates of potential gas resources made by other organizations which come to the attention of the Committee and may, from time to time, as deemed appropriate, prepare publications dealing with the comparison of the work of the Potential Gas Committee with that of other organizations. The Committee on Definitions and Procedures will also serve as liaison with the U.S. Geological Survey Resource Appraisal Group and other such organizations as are involved in the work of estimation of potential gas resources.

Membership

Chairman, appointed by the PGC Chairman, and approved by the Executive Committee. Four members of the Potential Gas Committee, appointed by the Chairman of the Committee on Definitions and Procedures, with approval of the PGC Chairman. PGC Chairman, ex officio; PGA Director, ex officio.

Time and Site Committee

This Committee will select an appropriate location and date for each national PGC meeting which will serve best the needs of the Committee. Once the site and date of each meeting have been selected by the Committee, the Potential Gas Agency will be charged with the responsibility of completing the arrangements for the meeting. The Time and Site Committee will also coordinate any regional meetings which are scheduled by Regional Vice Chairmen in order that the dates of such meetings shall not be in conflict.

Membership

Chairman, appointed by the PGC Chairman, and approved by the Executive Committee. Two members

of the Potential Gas Committee, appointed by the Chairman of the Time and Site Committee, and approved by the PGC Chairman. Regional Vice Chairmen, ex officio; PGC Chairman, ex officio; PGA Director, ex officio.

COMMUNICATIONS

Communication Between Committees

The formal channel of communication shall be from the Area Work Committees to the Potential Gas Committee to the Potential Gas Agency to the American Gas Association Gas Supply Committee and vice versa.

Public Communication

Members of the Potential Gas Agency, the Potential Gas Committee, and the Area Work Committees are encouraged to publicize and explain their work. These efforts should be limited to explaining the methodology used, comparative methodology, and the strengths and limitations of the work. When acting as spokesmen for the Committee, members shall refrain from interpreting study results in terms of national policy needs or required industry incentives. Members who are called upon to make talks and write papers on behalf of the Committee should submit texts to the Potential Gas Agency for comment and policy review.

MEMBERSHIP OF THE POTENTIAL GAS AGENCY AND POTENTIAL GAS COMMITTEE

POTENTIAL GAS AGENCY

Harry C. Kent, Director
James C. Donaldson, Assistant to the Director
Ladine Rintoul, Administrative Assistant

POTENTIAL GAS COMMITTEE

George C. Grow, Jr., Chairman
Charles J. Crowley, Vice Chairman, Western Region
James K. Curry, Vice Chairman, Central Region
Robert W. Gallagher, Vice Chairman, Eastern Region
Merlin A. Johnson, Secretary

Executive Committee

E. Floyd Humphries, Chairman

Charles M. Allen
A. M. Derrick
Jimmie C. Herrington
Richard J. Murdy
E. A. Rassinier

ex officio:
Donald W. Axford
Richard J. Burgess
Robert J. Cordell
Charles J. Crowley
James K. Curry
Robert W. Gallagher

George C. Grow, Jr.
Merlin A. Johnson
Robert B. Kalisch
Harry C. Kent
Charles P. Moreton
Charles L. Neumeyer
A. A. Wilkins (alt.)

Editorial Committee

Charles L. Neumeyer, Chairman

Charles J. Crowley
A. M. Derrick
E. Floyd Humphries
E.A. Rassinier

ex officio:
George C. Grow, Jr
Harry C. Kent

Committee on Definitions and Procedures

Robert J. Cordell, Chairman

Richard J. Burgess
Donald E. Hallinger
Jimmie C. Herrington
David A. Rochester

ex officio:
George C. Grow, Jr.
Harry C. Kent

Time and Site Committee

Richard J. Burgess, Chairman

Jimmie C. Herrington
ex officio:
Charles J. Crowley
James K. Curry

Robert W. Gallagher
George C. Grow, Jr.
Harry C. Kent

Area Work Committees

Area	*Chairman*	*Vice Chairman*
A	E. Perry Bendler	Porter J. Brown
B	Billy C. Cook	John M. Richart
C	William E. Mantek	John Avila
D	Paul Mounce	Billy D. Brown
E	Charles R. Brammell	—
G	Jeffery V. Morris	Bill C. Burkman
H	James A. Barlow, Jr.	C. Keith Fisher
I	Robert D. Habbit	—
J-N	Alan F. Chatfield	Joe E. McGarrah
J-S	Charles M. Allen	James F. Fleming
K	Alexander Sisson	—
L	William F. Edmondson	Wesley E. Franklin

Observers

Donald W. Axford, D. W. Axford & Associates Ltd. (Canada)
Lucio A. D'Andrea, Energy Resources Development (DOE)
Gordon L. Dolton, U.S. Geological Survey
W. Timothy Dowd, Interstate Oil Compact Commission
E. Bruce Hagen, National Assn. of Regulatory Utility Commissioners
Tommie C. Hillis, Federal Energy Regulatory Commission (alternate)
Robert B. Kalisch, American Gas Association
Gordon W. Koelling, Energy Information Administration (DOE)
B. J. Moore, U.S. Bureau of Mines
J. Glenn Seay, Institute of Gas Technology
John C. Sharer, Gas Research Institute
Wayne M. Thompson, Federal Energy Regulatory Commission
A. A. Wilkins, TransCanada PipeLines (Canada, alternate)

Representatives

Charles L. Neumeyer — Gas Distributors
Charles P. Moreton — Pipelines

Honorary Technical Advisors

Charles M. Allen
B. Warren Beebe
Mark V. Burlingame
John M. Hanley
Richard J. Murdy
E. A. Rassinier
Lyon F. Terry

Members-at-Large

Francis J. Barker
A. M. Derrick
John D. Haun
Jimmie C. Herrington
Michael J. Popovich
Charles E. Smith
Franklin D. Stockman
Gordon K. Zareski

ALLEN, C.M. (8)+: Consultant, Expl. & Prod. Affairs — Industry & Govt., No. Am. Expl. & Prod. Div., Phillips Petrol. Co., Bartlesville, OK 1944-. Adv. Board to Dept. of Geol., Univ. KS 1973-. Mem. Am. Assn. Petrol. Geol. (Comm. on Statistics of Drlg.). Nat. Petrol. Council(Comm. on Emergency Preparedness, 1974-76, Comm. on U.S. Energy Outlook 1970-73). Fed. Power Comm. Natl. Gas Surv. (Gas Supply Task Force 1971-75). Has testified in numerous state conservation agency, state and federal courts, and Fed. Power Comm. proceedings (including all major area and national rate proceedings), and hearings before Senate and House Congressional Committees. (Honorary Technical Advisor.)

AXFORD, Donald W. (6): Pres., D.W.Axford & Associates, Consulting, Calgary, Canada 1978-. Director: Frio Oils Ltd., Strand Oil & Gas Ltd.; Rock Ore Mining. DB&K Oils Ltd., Pres. 1977-78. Petro-Canada Inc., Sr. V. Pres. Expl & Dir.; Pan Arctic Oils Ltd., Dir. 1976-77. Mobil Oil Canada, V. Pres., Expl. & Dir. (Calgary) 1948-76. Mem. Am. Assn. Petrol. Geol. (Adv. Council, Energy Minerals Div. Tar Sands Councilor), Canadian Petrol. Geol., Geol. Assn. Canada, Prof. Engr. Alberta, Soc. Econ. Paleon. & Min. (CANADA — Chairman.)

BARKER, Francis J. (4): V. Pres., Nat. Gas & Gas Liquids Dept., Oil & Gas Div., Union Oil Co. of CA, Los Angeles, CA 1971-; Gen. Mgr. (Chicago) 1970-71; Mgr. Opr. (Midland) 1967-70; Mgr. Engr. (Thums-Long Beach Co.) 1965-67; Dist. Mgr. (Santa Maria) 1963-65; Mgr. Expl. (Canary Islands, Spain) 1960-63; Supt. (Coalinga) 1957-60; Engr. 1948. Mem. Am. Petrol. Inst., Am. Inst. Min. Engr., Am. Assn. Petrol. Geol., Gas Processors Assn. (Board of Dir.), Am. Gas Assn. (Steering Comm., Gas Supply).

BEEBE, B.W. (8): Geol., Geophysicist & Energy Consultant, Laguna Hills, CA 1980-, Geol., Geophysicist & Energy Consultant (Boulder, CO) 1972-80. Millison & Beebe (Partner) 1969-72. M. M. & B., Inc., V. Pres. & Sec., 1964-72. Ind. Geol. and Geophysicist 1959-64. Keating Drlg. Co., V. Pres. and Dir. 1955-58. Manhart, Millison & Beebe (Partner) 1950-55. Anderson-Prichard Oil Corp., Expl. Mgr. 1947-50. Bay Petrol. Corp., Ch. Geol., Expl. Mgr. (organized expl. dept.); V. Pres. 1942-47. Lerke & Whortan, Assoc. Cons., 1939-41. British-American Oil Prod. Co., Div. Geol. 1938-39. Shell Petrol. Corp., Geol. and Asst. to V. Pres. Expl., 1935-38. KS Emergency Relief Comm., Geol. 1934. Mem. Am. Assn. Advancement Science (Fellow), Geol. Soc. Am. (Fellow), Am. Assn. Petrol. Geol. (Hon. mem.), OK Geol. Soc. (Hon. mem.), Rocky Mtn. Assn. Geol. (Hon. mem.), Am. Arbitration Assn., Am. Gas Assn., Assn. Prof. Geol. Scientists, KS Geol. Soc., Oklahoma City Geol. Soc., Soc. Expl. Geophysicists, Soc. Ind. Prof. Earth Scientists, Soc. Petrol. Engr., Rocky Mtn. Nat. Gas Men's Assn. (Honorary Technical Advisor.)

BURGESS, Richard J. (6): Exec. V. Pres., Northern MI Expl. Co., Jackson, MI 1980-; V. Pres. 1967-80. Consumers Power Co., Exec. Dir. Expl. 1967-80; Expl. Supv. 1963-67. Panhandle Eastern Pipe Line Co., Geol. 1962. Plymouth Oil Co., Geol. 1960-61. Imperial Oil Ltd. (Canada), Geol. 1954-60. Mem. Am. Assn. Petrol. Geol. (CPG #462). Geol. Soc. Am., MI O&G Assn., MI Basin Geol. Soc., Ontario Petrol. Inst.

BURLINGAME, Mark V. (8): Burlingame Consultants, Bradenton, FL 1967-. Nat. Gas Pipeline Co. of Am., Planning, Construction & Opr. Pipeline System, Offshore and Onshore Expl. Programs, Gas Storage in Aquifers fms. (dev.), Sr. V. P. Gas. Opr. (ret.) 1930-67. Served the Dept. of Interior as the natural gas operations consultant and as the U.S. representative observer to the United Nation's European Economic Committee's Gas Energy Committee, served on technical natural gas missions behind the Iron Curtain. Mem. Am. Assn. Petrol. Geol. (Cert.), Am. Gas Assn., Am. Geol. Inst., Assn. Ind. Pet. Geol., Am. Pet. Inst., So. Gas Assn. (Honorary Technical Advisor.)

CORDELL, Robert J. (3): Consultant, Cordell Reports Inc., Richardson, TX 1980-; Consultant (Dallas, TX) 1977-80. Suntech Inc., Sr. Prof. Scientist, Energy Tech. and Sciences Dept., Res. and Engr. Div. (Richardson, TX) 1975-77. Sun Oil Co., Research Scientist, Sr. Research Scientist 1970-75; Sr. Sec. Mgr., Geol. Research 1963-70; Mgr. Geol. Research 1955-63; Research Paleontologist-Research Geol.-Sr. Research Geol. 1951-55. Mem. Am. Assn. Adv. Sci. (Fellow), Am. Assn. Petrol. Geol., Dallas Geol. Soc. (Hon. Life Mem.), Dallas Geophys. Soc., Geol. Soc. Am. (Fellow), Paleon. Soc., Soc. Paleon. and Mineralogists.

CROWLEY, Charles J. (4): Consulting Reservoir Geol., El Paso Natural Gas Co., El Paso, TX 1977-; Sr. Reservoir Geol. 1965-77. Hercules Powder Co., Supv. 1962-65. Consultant (WY & AZ) 1958-62. Forest Oil Corp., Area Geol. 1953-59. Marathon Oil Co. (OH Oil), Scout-Area Geol. (Billings and Casper) 1949-53. Mem. Am. Assn. Petrol. Geol., El Paso Geol. Soc., Soc. Mining Engr., Reg. Geol. (AZ).

CURRY, James K. (8): Mgr., Rocky Mtn. Region, Panhandle Eastern Pipe Line Co., Denver, CO 1975-; Mgr. Expl. & Prod. (Pan Eastern Expl., Houston) 1973-75-; Mgr. Expl., Mgr. Geol., Dist. Geol., Geol., Jr. Geol. (Liberal, KS) 1946-72. Mem. Am. Assn. Petrol. Geol., Soc. Petrol. Engr., Rocky Mtn. Assn. Geol., Rocky Mtn. Nat. Gas Men's Assn., Assn. Prof. Geol. Scientists (Cert. #4353).

D'ANDREA, Lucio A. (4): Chief, Nat. Gas Div., Office of Oil & Gas, Energy Resource Development, U.S. Dept. of Energy, Washington, D.C. Experience of about 20 years in various aspects and activities of natural gas industry — production, transportation, distribution and alternate gas supplies. Mem. Soc. Petrol. Engr., Soc. Military Engr.

DERRICK, A.M. (8): Sr. V. Pres., Marketing, Rates, Regulatory Affairs, Customer Relations, El Paso Natural Gas Co., El Paso, TX 1977-; V. Pres. 1972-77; Asst. V. Pres. 1966-71; Dir., Reservoir Engr. 1960-65; Asst. Mgr., Reservoir Engr. 1958-60; Sr. Petrol. Engr.-Reservoir Engr. 1953-57. Stanolind Oil & Gas Co., Petrol. Reservoir Engr. 1947-53. Mem. Am. Assn. Petrol. Geol., Soc. Petrol. Engr., Soc. Petrol. Eval. Engr., Nat. Gas Mens' Assn.

DOLTON, Gordon L. (3): Proj. Chief, Resource Assessment Group-Domestic, Br. Oil and Gas Resources, U.S. Geological Survey, Denver, CO 1975-; Geol., Resource Appraisal

+Number in parentheses following name indicates number of Potential Gas Committee reports in which member participated.

Group 1974-75. Shell Oil Co., Staff Geol. (Houston) 1973-74; Staff head, Planning and Venture Development (Denver) 1963-66; Sr. Geol. (Okla. City) 1963-66; Geol. (WY) 1954-60. Shell Development Co., Research Geol. (Houston) 1960-63. Richfield Oil Corp., Geol. 1951-52. Mem. Am. Assn. Petrol. Geol., Geol. Soc. Am., Rocky Mtn. Assn. Geol.

DOWD, W. Timothy (2): Exec. Dir., Interstate Oil Compact Commission, Oklahoma City, OK. Involvement in a variety of governmental activities as either an observer or participant including Oklahoma House of Representatives and counsel to the Governor of Oklahoma. Mem. Am. Bar Assn., OK Bar Assn., Fed. Energy Bar Assn.

GALLAGHER, Robert W. (5): Mgr., Reserves and Deliverability, Southern Natural Gas Co., Houston, TX 1967-; Sr. Engr. 1962-67. Mem. Am. Assn. Petrol. Geol.

GROW, George C. Jr. (8): Consulting Geol., Westfield, NJ 1974-. Transcontinental Gas Pipe Line Corp., Ch. Geol.-Eastern area (NJ) 1950-73. The Peoples Natural Gas Co., Jr. Geol. to Ch. Geol. (PA) 1939-50. Standard Oil Co. (NJ), Geol. (Venezuela) 1938-39. Mem. Am. Assn. Petrol. Geol. (Cert. #31, Treas. 1974-76, Adv. Council 1976-, Fndn. Dev. Coord. 1973-), Am. Inst. Min., Met. & Petrol. Engr., Assn. Prof. Geol. Scientists (Cert. #1774), Geol. Soc. Am. (Fellow), Pittsburgh Geol. Soc. (Past Pres.), Am. Gas Assn. (Comm. Underground Storage 1951-73, Chmn. 1960-61; Task Group on Gas Storage Statistics, Chmn. 1964-71), Am. Petrol. Inst., PA Oil & Gas Assn., Ind. Oil & Gas Assn. WV, Lamont-Doherty Geol. Observatory, Columbia Univ. (Adv. Council), Fed. Power Comm. Natl. Gas Surv. (Underground Storage Task Force 1972-73; Prospective Expl. & Development Task Force 1975-).

HAGEN, E. Bruce (2): Commissioner, North Dakota Public Service Commission, Bismarck, ND 1961-. Deputy Motor Vehicle Registrar for North Dakota 1961. Farmer in Benson and Ramsey Counties in North Dakota 1956-. Mem. Mid-America Regulatory Comm., Natl. Assn. Reg. Util. Comm., Regional Energy Adv. Bd of U.S. Dept. of Energy, Regulatory Council.

HALLINGER, Donald E. (7): Mgr. Expl., Pacific Lighting Gas Development Co., Los Angeles, CA 1977-; Sr. Geol. 1966-77. Mem. Am. Assn. Petrol. Geol. (Cert.), Assn. Prof. Geol. Scientists (Cert., Past Sec.-Treas.), Soc. Econ. Paleon. & Min.

HANLEY, John M. (6): Retired, Omaha, NB 1973-. Northern Nat. Gas Co., V. Pres.-Gas Supply Studies 1965-73; V. Pres.-Long Range Planning 1963-65; V. Pres.-Gas Supply 1950-63; Supt. Prod. Head Dept. 1942-50; Prod. Engr. 1936-42; Gas Field Supt. (KS) 1933-36. Mem. Am. Assn. Petrol. Geol., Soc. Petrol. Engr., Am. Gas Assn. (Nat. Gas Reserves Comm. 1945-56; Chmn., Nat. Gas Prod. Comm. 1956), Natl. Petrol. Council (Comm. on U.S. Energy Outlook 1970-72), Fed. Power Comm. (Natl. Gas Surv., Gas Supply Task Force 1970-73), Adv. Comm. on Energy to Sec. Int. 1970-71.

HAUN, John D. (7): Prof. Petrol. Geol., Colorado School of Mines, Golden, CO 1955-. Barlow and Haun, Inc., Consultant 1957-. Petroleum Research Corp., V. Pres. 1952-57. Stanolind (Amoco), Geol. Party Ch. 1951-52. Mem. Am. Assn. Petrol. Geol. (Pres. 1979-80), Am. Geol. Inst. (Pres. 1981-82), Am. Inst. Prof. Geol. (Pres. 1976), Am. Petrol. Inst., Geochem. Soc., Geol. Soc. Am. (Fellow), Nat. Petrol. Council, Rocky Mtn. Assn. Geol. (Pres. 1968), Soc. Econ. Paleon. & Min.

HERRINGTON, J.C. (6): Mgr., Atlantic OCS Proj., ARCO Oil and Gas Co., Dallas, TX 1980-; Mgr., CO_2 Expl., Western Reg. 1978-80; Mgr., Expl. Permian Dist. (Midland, TX) 1973-78; Spec. Proj. & Dist. Geol. (Lafayette, LA) 1971-73; Dist. Geol. (Tyler, TX) 1962-71; Dist. Geol. (offshore LA) 1959-62; Area Geol. (Dallas) 1959; Geol. & Sr. Geol. (So. LA) 1953-58; Oil Scout (MS-AL) 1952-53. Mem. Am. Assn. Petrol. Geol., W. TX Geol. Soc., Am. Gas Assn., Am. Petrol. Inst., NM Geol. Soc., Assn. Prof. Geol. Scientists, Dallas Geol. Soc., Rocky Mtn. Assn. Geol.

HILLIS, Tommie C. (1) (alternate for Wayne M. Thompson): Gas Supply Branch, Office of Pipeline & Producer Regulation, Federal Energy Regulatory Commission, Washington, D.C.

HUMPHRIES, E. Hoyd (8): Asst. V. Pres., NAPECO Inc., Houston, TX 1980-; Natural Gas Pipeline Co. of Am., Mgr. Geol. (Expl. & Contracted Supply) (Houston) 1954-80. Claud B. Hamill, Independent 1949-54. Tidewater Assoc. Oil Co. 1946-49. Mem. Am. Assn. Petrol. Geol. (Cert.), Assn. Prof. Geol. Scientists (Cert.), Houston Geol. Soc.

JOHNSON, Merlin A. (5): Mgr.-Northeast Dist., ANR Production Co., Troy, MI, 1980-; American Natural Gas Production Co., Detroit, MI 1978-80; Michigan Natural Resources, V. Pres. Opr., MI Basin 1976-78; Michigan Consolidated Gas Co., Dir., Geol., Expl. & Gas Acquisition 1964-78; Mgr. Geol. Dept. (Grand Rapids, MI) 1959-64. Gulf Oil Corp., Zone Geol. & Staff Asst. Explor. Mgr., MI, IL & Andarko Basins 1949-59. Mem. Am. Assn. Petrol. Geol., Assn. Prof. Geol. Sci., MI Basin Geol. Soc., Engr. Soc. Detroit.

KALISCH, Robert B. (3): Director, Gas Supply and Statistics, American Gas Association, Arlington, VA 1975-. U.S. Air Force assignments (including Off. Scientific Research, Science and Tech. Staff Officer and Dir., Ionospheric Physics Lab.) 1951-75. Mem. Inst. Elec. and Electronics Engr., Research Soc. Am., Prof. Engr. (MA).

KENT, Harry C. (3): Director, Potential Gas Agency, Colorado School of Mines, Golden, CO 1976-; Prof. Geol. 1969-, Head, Geol. Dept. 1970-75, Act. Head, Geol. Dept. 1969-70, Assoc. Prof. Geol. 1967-69, Asst. Prof. Geol. 1964-67, Instructor Geol. 1956-64. The California Co., Geologist (FL & LA) 1953-56. Stanford Univ., Teaching Asst. 1953. Mem. Am. Assn. Adv. Sci., Am. Assn. Petrol. Geol., Geol. Soc. Am. (Fellow), Rocky Mtn. Assn. Geol. (Ed., Colorado Geology 1978-80), Soc. Econ. Paleon. & Min.

KOELLING, Gordon W. (2): Sr. Specialist, Br. Natural Gas Statistics, Energy Information Adm. (DOE), Washington, DC 1977-. U.S. Bureau Mines, Washington, DC 1957-77. Corps of Engr. 1951-57.

MOORE, Billy J. (3): Chief, Unit of Helium Resources Evaluation, Division of Helium Operations, U.S. Bureau of Mines, Amarillo, TX 1961-. U.S. Air Force 1958-61. Phillips Petrol. Co., Jr. Engr. (McGregor, TX) 1957-58. Mem. Reg. Prof. Engr. (TX).

*MORETON, Charles P. (3): Pres. and Ch. Exec. Off., Gas Trans. Services Div., Texas Gas Transmission Corp., Owensboro, KY 1977-; Exec. V. Pres., Gas Trans. Div. (Houston, TX); V. Pres. Gas Supply, Mgr. Gas Supply, Mgr. Gas Contracts, Supv. Gas Contracts, Gas Contract Rep., 1953-. AR LA Gas Co., Gas Engr. 1950-53. Mem. Am. Gas Assn., Interstate Nat. Gas. Assn. Am., Nat. Gas Men of Houston, So. Gas Assn.

MURDY, Richard J. (8): President, CNG Producing Co., New Orleans, LA 1979-; CNG Producing Co., V. Pres. (Clarksburg, WV) 1973-78; Consolidated Natural Gas Co., Asst. to Chmn. of Bd. 1968-73; Asst. Treas. (New York) 1963-68; Asst. to Pres. 1957-63. New York State Natural Gas, Chief Geol. (Pittsburgh) 1952-57. Consolidated Gas, Underground Storage Eng. (Pittsburgh) 1948-52. Mem. Am. Assn. Petrol. Geol., Am. Gas Assn., Assn. Ind. Petrol. Geol., Geol. Soc. Am., So. Gas Assn., Soc. Petrol. Eng.

**NEUMEYER, Charles L. (5): Sr. V. Pres., Brooklyn Union Gas Co., Brooklyn, NY. Mem. Am. Gas Assn.

POPOVICH, Michael J. (7): Deliverability Supervisor, Reserves Evaluation, Gas Supply, Texas Eastern Trans. Corp., Houston, TX 1971-; Head, Gas Reserve Dept. 1951-71. Sohio Petroleum, Res. Engr. (Oklahoma City) 1947-51. U.S. Navy, Communications Officer 1945-47. University of Pittsburgh, Inst. in Petrol. Engr. 1942-45. Mem. Am. Gas Assn., Houston Geol. Soc., Nat. Gas Men of Houston, Prof. Engr. (TX, LA), Soc. Petrol. Engr. (AIME).

RASSINIER, E. A. (8): Dir.-Resource Planning, Trunkline Gas Co., Houston, TX 1964-; Ch. Petrol. Engr. 1953-64. Phillips Petrol. Co. (Prod. Dept.), Supv. Petrol. Engr. (Bartlesville, OK) 1951-52, Reg. Reservoir Engr. (Houston) 1947-50, Div. Reservoir Engr. (Oklahoma City) 1946, Petrol. Engr. (Bartlesville) 1944-45; (Refining Dept.) Assoc. Design Engr. (Bartlesville, Borger, Kansas City) 1942-43. Mem. Am. Assn. Petrol. Geol., Am. Inst. Min., Met. & Petrol. Engr., Soc. Petrol. Engr., Houston Engr. & Scientific Soc., Houston Geol. Soc., Gas Res. Inst. Indus. Tech. Adv. Comm. (Unconventional Nat. Gas), Reg. Prof. Engr. (TX & MO).

ROCHESTER, David A. (5): The Fuels Planning Engineer, Public Service Elec. & Gas Co., Newark, NJ 1977-; The Natural Gas Engr. 1971-77; Engr. 1966-71. Mem. Assoc. Gas Distr. (Vice Ch.-Oper. Comm. & Ch. Computer Modeling Comm.), Am. Gas Assn., NJ Gas Assn., Soc. Petrol. Engr., Petrol. Expl. Soc. of NY, Am. Inst. Min., Met. & Petrol. Engr. Assn.

SMITH, Charles E. (6): Pres., Transworld Gas Systems, Inc., Whittier, CA 1971-. Union Oil Co. CA, Mgr. Nat. Gas and Gas Liquids Dept. (Los Angeles, CA), 1967-70. (PGC Area K Work Comm. Chmn. 1966.)

SEAY, J. Glenn (1): Executive Advisor, Analysis and Planning, Institute of Gas Technology, Chicago, IL 1965-. Butler Mfg. Co., Sr. Engr., Oil Field Equip. R&D (Kansas City, MO) 1956-61. Midwest Research Inst., Head, Process Sec. (Kansas City, MO) 1952-56, 1961-65. Socony-Mobil Oil Co., Process Engr. (Augusta, KS) 1950-52.

SHARER, John C. (1): Asst. Dir., Unconven. Nat. Gas, Gas Research Institute, Chicago, IL 1978-. Consultant (Farmington, ME) 1975-78. Institute of Gas Technology, Supervisor (Chicago, IL) 1972-75. Procon Inc., Process Engineering Dept. (Des Plaines, IL) 1971-72. Mem. Am. Chem. Engr., Prof. Engr. (IL, ME).

STOCKMAN, Franklin D. (2): V. Pres. & Asst. to Exec. V. Pres., Northern Natural Gas Co., Omaha, NB 1980-; V. Pres. & Asst. to Pres., Natural Gas Group 1977-80; V. Pres.-Gas Supply 1965-77; Dir. Gas Reserves & Availability 1958-65; Staff Asst. & Chief of Services-Reserves & Availability 1956-58. Phillips Petroleum Co., Supr. Engr. Statistics 1944-56. Mem. Am. Assn. Petrol. Geol., Am. Gas Assn., Soc. Petrol. Engr., Interstate Nat. Gas Assn. Am., So. Gas Assn.

TERRY, Lyon F. (8): Ret., Ridgewood, NJ 1967-. Lehman Bros., Assoc. 1957-66; Chase Nat. Bank, V. Pres. & Gas Engr. 1937-57; Ralph E. Davis Engr. (NYC), V. Pres. 1927-37; ESSO (NJ), Gas Eval. Engr. 1925-27; O&G Engr. (OK) 1915-25. Mem. Soc. Petrol. Engr., Am. Gas Assn. (Nat. Gas Reserves Comm., organized and Chmn. 1944). (PGC organizer, first Chmn., and Hon. Tech. Adv.)

THOMPSON, Wayne M. (1): Chief, Gas Supply Branch, Office of Pipeline & Producer Regulation, Fed. Energy Regulatory Comm., Washington, DC 1967-. Geol. Consultant (Oil & Gas) (El Dorado, AR) 1961-67. Robbins Petrol. Corp., Geol.-Engr. (Longview, TX) 1959-1961. Petroleum, Inc., Geol. (Shreveport, LA) 1958-59. McAlester Fuel Co. (Magnolia, AR) 1954-58

WEBB, David O. (1) (alternate for John C. Sharer): Gas Research Institute, Chicago, IL.

WILKINS, A. A. (2): V. Pres., Gas Supply Dept., Alberta Div., TransCanada PipeLines, Calgary; Manager of Reserves, Chief Geol., Geol. 1965-. Hudson's Bay Oil & Gas, Exploration Geol. 1960-65. Mem. Canadian Soc. Petrol. Geol., Am. Assn. Petrol. Geol., Assn. Canadian Inst. Min. & Met., Ontario Nat. Gas Assn. (CANADA — Vice Chairman.)

ZARESKI, Gordon K. (1): Sr. V. Pres., H. Zinder & Assoc., Washington, DC 1979-. Department of Energy, Office of the Oil & Gas Information System, Director (Washington) 1977-79. Federal Power Comm., Bureau of Natl. Gas, Chief of Planning & Development (Washington) 1969-77. Mem. Am. Assn. Petrol. Geol., Geol. Soc. Washington, DC.

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*Pipelines representative.
**Gas Distributors representative.

AREA A

E. Perry Bendler, Chairman
Porter J. Brown, Vice Chairman

BENDLER, E. Perry (8): Prod. Reserve. Geol., The East Ohio Gas Co., Cleveland, OH 1955-. Mem. Am. Assn. Petrol. Geol. (Comm. on Statistics of Drlg.), Assn. Prof. Geol. Scientists (Cert. #2473), No. OH Geol. Soc., OH Geol. Soc., OH O&G Assn.

BENNETT, William E. (8): Pres., Phoenix Hydrocarbon, Ltd., Charleston, WV 1979-; Pres. GASAMEX, Ltd., Pres. (Charleston, WV) 1977-and V. Pres.-Expl., Monitor Petrol. Corp., (NYC Charleston, WV) 1976-; Geol. Geophysicist 1974-76, Monitor Resources Corp., NYC, Cons. 1976-, Lunsford Granite Materials, Elberton, GA, V. Pres. 1976-, United Fuel Gas Co., Sr. Geophysicist 1969-74, Geophysicist 1962-68, Geol. 1957-61. Mem. Am. Assn. Petrol. Geol., Assn. Prof. Geol. Scientists (Cert. #1642, Past Pres. WV Sec.), Soc. Expl. Geophysics, Ind. O&G Assn. WV, OH Geol. Soc., Appalachian Geol. Soc., Fed. Power Comm. Natl. Gas Surv. (Tech. Adv. 1975-76), Am. Gas Assn. (Atl. Action Comm 1974-75).

*BROWN, Porter J. (3): Chief-Geol. Serv., Columbia Gas Trans. Corp., Charleston, WV 1973-. United Fuel Gas Co., Ch. Geol. 1960-73, Geol. 1957-60, Asst. Geol. 1950-57. Mem. Am. Assn. Petrol. Geol., Geol. Soc. Am., Appalachian Geol. Soc., Geol. Soc. KY, Geol. Soc. OH, Geol. Soc. PA, Assn. Prof. Geol. Scientists (Cert. #2463), Gas Res. Inst. Indus. Tech. Adv. Comm. (Unconventional Nat. Gas), Prof. Petrol. Engr. (KY #4927), Prof. O&G Engr. (WV #5118).

FREUND, Paul G. (8): Ch. Geol., The Peoples Nat. Gas Co., Pittsburgh, PA 1952-. State of PA, Engr. 1950-52. Mem. Am. Assn. Petrol. Geol., Am. Gas Assn., Pittsburgh Geol. Soc. (Past Pres.).

GROW, George C. Jr. (8): Consulting Geol., Westfield, NJ 1974-. Transcontinental Gas Pipe Line Corp., Ch. Geol.-Eastern Area (NJ) 1950-73; The Peoples Natural Gas Co., Jr. Geol. to Ch. Geol. (PA) 1939-50; Standard Oil Co. (NJ), Geol. (Venezuela) 1938-39. Mem. Am. Assn. Petrol. Geol. (Cert. #31, Treas. 1974-76, Adv. Council 1976-, Endn. Dev. Coord. 1973-), Am. Inst. Min., Met. & Petrol. Engr., Assn. Prof. Geol. Scientists (Cert. #1774), Geol. Soc. Am. (Fellow), Pittsburgh Geol. Soc. (Past Pres.), Am. Gas Assn. (Comm. Underground Storage 1951-73, Chmn. 1960-61; Task Group on Gas Storage Statistics, Chmn. 1964-71), Am. Petrol. Inst., PA Gas Assn., Lamont-Doherty Geol. Observatory, Columbia Univ. (Adv. Council), Fed. Power Comm. Nat'l. Gas Surv. (Underground Storage Task Force 1972-73; Prospective Expl. & Development Task Force 1975-).

HEATHCOTE, Clifton J. (6): Mgr., Gas Procurement, Consolidated Gas Supply Corp., Clarksburg, WV 1975-; Ch. Geol. 1965-75. NY State Nat. Gas Corp., Chief Geol. 1955-65. International Petrol., Field Geol. (Bogota, SA) 1953-55. Peoples Nat. Gas Co., Geol. (Pittsburgh) 1950-53. Mem. Am. Assn. Petrol. Geol., Am. Petrol. Inst., Am. Gas Assn., Pittsburgh Geol. Soc., Appalachian Geol. Soc. (PGC Sec. 1972-77).

LEEPER, Wayne S. (2): Chief Geol. & Mgr., Expl., National Fuel Gas Supply Corp., Buffalo, NY 1974-. United Natural Gas Co. & The Sylvania Corp., Chief Geol. (Oil City, PA) 1969-74; Geol. 1961-69. Mem. Am. Assn. Petrol. Geol., Northern Appalachian Geol. Soc. (Pres. 1965-66), Am. Petrol. Inst. (Penn York Chapter), PA Oil, Gas & Min. Assn. (Bd. Dir. 1976-), Cert. Prof. Geol. Scient. (No. 4308).

**MEHRING, Edmund K. (2): Exec. V. Pres. & Ch. Oper. Officer, Fuel Resources, Inc. (B.U.G. Subsid.), Brooklyn, NY 1980-; V. Pres. 1977-80; Mgr. Exploration 1977-; Mgr. Spec. Proj. 1976-77; Mgr. Tech. Serv. Dept. 1968-76; Asst. Engr. Manuf. 1964-68; Gen. Supt. Greenpoint Plant 1963-64; Supt. Dist. Dept. 1961-63; Supt. Holder Dist. 1958-61; Asst. Supt. 1951-58; Asst. to Supt. 1948-51; Jr. Engr. 1946-48. Mem. Am. Gas Assn. (Mem. Expl. Com. and First V. Chmn.), Assn. Gas Distr., Nat. Assn. Corr. Engr., Soc. Adv. Mgmt., Yale Engr. Assn.

NEWSOM, Max (1): Exploration Advisor, Gulf Oil Expl. & Prod. Co., New Orleans, LA 1949-. Mem. Am. Assn. Petrol. Geol., New Orleans Geol. Soc., Southeastern Geophys. Soc.

RAGSDALE, Tommie R. (3): Ch. Geol., Ray Resources, Charleston, WV 1973-. Consolidated Gas Supply Corp., Development Geol. (Clarksburg) 1966-73; McCullough Tool Co., Engr. Geol. 1962-66. Mem. Appalachian Geol. Soc. (Past V. Pres.).

SHERMAN, Carl W. (7): Assoc. Prof. Petrol. & Nat. Gas Engr., PA State Univ., Univ. Park, PA 1975-. Honeoye Storage Corp., Mgr. Opr. 1974-75; NY State Public Serv. Comm., Principal Systems Planner, Gas Division 1971-74; NY State Div. Min. Resources, Director 1964-71; IL Geol. Surv., Head Petrol. Engr. Sec. 1957-64; J B & M Inc., Tex-Canadian Oil Corp., Marathon, The California Co. 1948-57. Mem. Am. Gas Assn., Am. Petrol. Inst., Soc. Petrol. Engr., Fed. Power Comm. Tech. Adv. Comm. (Natl. Gas Surv.), Interstate Oil Compact Comm. 1957-74.

WIGAL, James M. (2): Geol., Peoples Nat. Gas Co., Pittsburgh, PA 1975-. U.S. Bureau of Mines (DOE), Geol. (Morgantown, WV) 1974-75. Mem. Am. Assn. Petrol. Geol., Soc. Econ. Paleon. & Min., Assn. Prof. Geol. Sci., Pittsburgh Geol. Soc.

AREA B

Billy C. Cook, Chairman
John M. Richart, Vice Chairman

BOWEN, David G. (3): Eason Oil Co., New Orleans, LA 1978-. Florida Gas Expl. Co., Div. Prod. Geol., New Or-

*Pipelines representative.

**Gas Distributors representative.

leans, LA 1970-78. Chevron Oil Co., Expl. Geol. 1967-69, Geophysicist 1965-67, Development Geol. 1961-65, Expl. Geol. 1959-61. United Fuel Gas Co., Geol. 1955-57. Mem. Am. Assn. Petrol. Geol., New Orleans Geol. Soc.

COOK, Billy C. (4): Geol., The Louisiana Land and Exploration Co., New Orleans, LA 1972-. Chevron Oil Co., Dev. & Expl. Geol. 1967-72. Mem. Am. Assn. Petrol. Geol., Soc. Econ. Paleon. & Min., New Orleans Geol. Soc.

*GALLAGHER, Robert W. (5): Mgr. Reserves and Deliverability, Southern Natural Gas Co., Houston, TX 1967-; Sr. Engr. 1962-67. Mem. Am. Assn. Petrol. Geol.

MOORE, William H. (3): State Geol. of MS and Director, MS Geol. Surv., Jackson, MS 1965-. MS Geol. Surv., Stratigrapher 1960-65. Shell Oil Co., Stratigrapher 1956-60. Mem. Am. Assn. Petrol. Geol., Assn. Prof. Geol. Scientists, Assn. Am. State Geol., MS Geol. Soc., MS Acad. Science.

RICHART, John M. (3): Dist. Expl. Geol., Union Oil Co. of CA, Jackson, MS 1975-. Pure Oil Co. (prior to merger with Union), Expl. Geol. (IL, MI and Appalachian Basins) 1969-75. Mem. MS Geol. Soc., Jackson Geophysical Soc., Am. Assn. Petrol. Geol.

SPOONER, Harry (3): Gen. Partner, Spooner Petrol. Co., Jackson, MS 1976-. Pruet & Hughes, Consulting Geol. 1971-76. Cons. and Independent Geol. (Monroe, LA) 1963-71. CO O&G Corp., Dist. Geol. (SE U.S.) 1957-63. CA Co., Dev. Geol. 1955-57. Mem. Am. Assn. Petrol. Geol. (CPG #329), MS Geol. Surv.

TURNER, Don (1) (alternate for John M. Richart): Union Oil Co. of California, Jackson, MS.

**TWINER, James W. (3): Pres., Petroleum Resources Co., Jackson, MS 1979-, Grace Petroleum Corp., Expl. Mgr. (Jackson, MS) 1978-79. Florida Gas Expl. Co., Geol. 1974-78. Union Oil Co. of CA, Geol. 1972-74. Skelly Oil Co., Geol. 1968-72. Chevron Oil Co., Geol. Asst. 1963-68. Mem. Am. Assn. Petrol. Geol., MS Geol. Soc.

AREA C

William E. Mantek, Chairman
John Avila, Vice Chairman

AVILA, John (7): Expl. Geol., Ashland Exploration, Inc., Ashland, KY 1963-. Ryan Oil Co., Expl. Geol. & Ch. Geol. (Evansville) 1951-63. National Geophysical Co., Inc., Computer (Dallas) 1951-63. Mem. Am. Assn. Petrol. Geol., Soc. Expl. Geophysicists, IN Acad. Science, IN-KY Geol. Soc., Appalachian Geol. Soc. (Pres.), KY O&G Assn. (Dir. & Tech. Chmn.)

BARRATT, Michael W. (1): Manager, MI Basin Div., Michigan Oil Co., Alma, MI 1978-; Staff Geol., 1975-78. MI Gas Utilities Development Co., Staff Geol. (Hastings, MI) 1972-75. MI Consolidated Gas Co., Staff Geol. (Detroit, MI) 1969-72. Mem. Am. Assn. Petrol. Geol., MI Basin Geol. Soc. (past pres., vice pres. and treas.), MI Oil and Gas Assn. (Bd. of Dir.).

*Pipelines representative.
**Gas Distributors representative.

**BURGESS, Richard J. (6): Exec. V. Pres., Northern MI Expl. Co., Jackson, MI 1980-; V. Pres. 1967-80. Consumers Power Co., Exec. Dir. Expl. 1967-80; Expl. Supv. 1963-67. Panhandle Eastern Pipe Line Co., Geol. 1962. Plymouth Oil Co., Geol. 1960-61. Imperial Oil Ltd. (Canada), Geol. 1954-60. Mem. Am. Assn. Petrol. Geol. (CPG #462), Geol. Soc. Am., MI O&G Assn., MI Basin Geol. Soc., Ontario Petrol. Inst.

HOWARD, Richard H. (2): Geol., Head of Oil & Gas Sec., IL State Geol. Surv., Urbana, IL 1958-. Phillips Petrol. Co., Geol. 1957-58. U.S. Geol. Survey, CO Plateau Uranium Exploration Project, Geol. 1954-57. Mem. Am. Assn. Petrol. Geol., Soc. Petrol. Engr., Am. Inst. Min., Met. & Petrol. Engr., IL Geol. Soc.

KELLER, Stanley J. (2): Geol., Petroleum Section, IN Geol. Survey, Bloomington, IN 1953-. Mem. Am. Petrol. Ins., IN-KY Geol. Soc., IN Geol.

*LUNDY, Curtis L. (7): Manager, Storage & Development Geol., MI Consolidated Gas Co., Detroit, MI 1972-. Am. Nat. Gas Co., Manager Storage Geol. 1963-72. Humble O&R Co., Staff Geol. 1958-63. Mem. Am. Assn. Petrol. Geol. (CPG #713), Soc. Petrol. Engr., MI Basin Geol. Soc.

MANTEK, William E. (5): Staff Geol., Expl. Dept., Northern MI Expl. Co., Jackson, MI 1976-. Consumers Power Co., Sr. Geol. 1965-76. MI Geol. Surv., O&G Sec., Geol. 1956-65. Mem. Am. Assn. Petrol. Geol. (Cert.), MI Basin Geol. Soc.

MEFFORD, Nace E. Jr. (7): Exec. V. Pres., Enterprise Petroleum, Houston, TX 1979-. Patrick Petroleum Corp., V. Pres. & Mgr. Property Acquisition 1973-79; Div. Mgr. (OK, Rocky Mtn., N. TX) 1970-73. Ashland Oil, Mgr. Property Acquisition 1967-69; Div. Mgr. (OH, MI, Canada) 1964-67; Chief Petrol. Engr. 1953-64; Field Geol. & Engr. (MI basin) 1948-53. Mem. Soc. Petrol. Engr. of Am. Inst. Min. Met. & Petrol. Engr., Soc. Petrol. Eval. Engr.

AREA D

Paul Mounce, Chairman
Billy D. Brown, Vice Chairman

BROWN, Billy D. (1): Sr. Staff Petrol. Engr., Lone Star Gas Co., Dallas, TX 1974-. Eppler, Guerin & Turner, Acct. Exec. 1967-74. Cornell Oil Co., Petrol. Engr. 1966-67. Texas Pacific Oil Co., Staff Petrol. Engr. 1962-66. Texas Pacific Coal & Oil Co., Petrol. Engr. 1953-62. Mem. Nat. Gas Soc. No. TX, Soc. Petrol. Engr. of Am. Inst. Min. Met. & Petrol. Engr.

BURGESS, Ferrell L. (7): Dist. Mgr., Pennzoil Prod. Co., Shreveport, LA 1980-; Domestic Region Exploitations Mgr. (Houston) 1978-80; Sr. Geol. 1975-78; Dist. Res. Dev. Mgr. 1970-74; Geol. 1967-69. Union Prod. Co., Geol. 1955-67. Mem. Am. Assn. Petrol. Geol., Am. Petrol. Inst., Shreveport Geol. Soc.

**BOYINGTON, Lowell D. (2): Prod. Engr., Arkansas Western Gas Co., Fayetteville, AR 1967-. Texaco Inc., Area Engr. (Kermit, TX) 1962-67. Mem. Reg. Petrol. Engr. AR, Soc. of Petrol. Engrs., Am. Inst. Min., Met. & Petrol. Engr.

FEEMSTER, Lee T. Jr. (7): Geol. Consultant, Abilene, TX 1974-. Texas Pacific Oil Co., Expl. Geol. & Development Geol. 1955-74. Stanolind (Amoco), Expl. Geol. 1951-55. Mem. Am. Assn. Petrol. Geol., Abilene Geol. Soc., West Texas Geol. Soc.

MOUNCE, Paul (7): Expl. Mgr., Petrosil Resources Inc., Dallas, TX 1980-. Ind. Petrol. Geol. 1978-80. Maynard Oil Co., Ch. Geol. 1974-78. Lone Star Gas Co., Staff & Corporate Development. Texas Pacific Oil Co., Dist. Geol. Fifteen Oil Co., Dist. Geol. Warren Petrol. Corp., Dist. Geol. Mem. Am. Assn. Petrol. Geol., Am. Inst. Min., Met. & Petrol. Engr.

*RICHARDS, G.L. (Jack) (3): Ch. Geol., V. Pres. Expl., Sr. V. Pres. Expl. & Prod., Coastal States Gas Corp., Houston, TX 1964-. Std. Oil Co. TX (Chevron), Geol., Geophysicist, Manager Econ. Eval., Dist. Geol. 1948-64. Mem. Am. Assn. Petrol. Geol. (Cert.), Assn. Prof. Geol. Scientists (Cert.), Am. Petrol. Inst., Independent Petrol. Assn. Am., Dom. Petrol. Council (Dir.).

SPENCER, Walter E. (3) (alternate for G. L. Richards): Coastal States Gas Corp., Houston, TX.

AREA E

Charles R. Brammell, Chairman

BRAMMELL, Charles R. (2): Consulting Devel. Geol., Graham Energy, Metairie, LA 1980-. CNG Producing Co., Mgr. Development (New Orleans) 1980; Chief Devel. Geol. 1977-80; Devel. Geol. 1973-77. Gulf Oil Corp., Expl. & Devel. Geol. 1960-73 and 1957-58. Sinclair Oil & Gas, Expl. & Devel. Geol. 1959-60. Hycalog, Mudlogging Engr. 1958-59. Mem. New Orleans Geol. Soc.

McELROY, John H. (1): Sr. Coord., Expl. & Prod. Serv., Texaco Inc., Bellaire, TX, 1977-; Expl. Coord. 1972-77; Midland Asst. Div. Mgr. 1969-72; Houston Div. Geol. 1967-69; Houston Asst. Div. Geol. 1961-67; Geol. 1958-61. Seaboard Oil Co., Geol., Asst. Dist. and Dist. Geol. 1951-58. Gulf Oil Corp., Surf. and Subsurf. Geol. 1948-51. Mem. Am Assn. Petrol. Geol.

*RASSINIER, E.A. (8): Dir.-Resource Planning, Trunkline Gas Co., Houston, TX 1964-; Ch. Petrol. Engr. 1953-64. Phillips Petrol. Co. (Prod. Dept.), Supv. Petrol. Engr. (Bartlesville, OK) 1951-52, Reg. Reservoir Engr. (Houston) 1947-50, Div. Reservoir Engr. (Oklahoma City) 1946, Petrol. Engr. (Bartlesville) 1944-45; (Refining Dept.) Assoc. Design Engr. (Bartlesville, Borger, Kansas City) 1942-43. Mem. Am. Assn. Petrol. Geol., Am. Inst. Min., Met. & Petrol. Engr., Soc. Petrol. Engr., Houston Engr. & Scientific Soc., Houston Geol. Soc., Gas Res. Inst. Indus. Tech. Adv. Comm. (Unconventional Nat. Gas), Reg. Prof. Engr. (TX & MO).

RIEKER, James D. Jr. (1): Mgr. Petrol Engr., Texas Gas Exploration Corp., Houston, TX 1980-; Sr. Res. Engr. and Res. Engr. 1976-80. Amoco Production Co., Res. Engr. and Operations Engr. 1974-76; Prod. Engr 1973-74. Mem. Soc. Petrol. Engr. of Am. Inst. Min., Met. & Petrol. Engr.

**ROCHESTER, David A. (5): The Fuels Planning Engineer, Public Service Elec. & Gas Co., Newark, NJ 1977-; The Natural Gas Engr. 1971-77; Engr. 1966-71. Mem. Assoc. Gas Distr. (Vice Ch.-Oper. Comm. & Ch. Computer Modeling Comm.), Am. Gas Assn., NJ Gas Assn., Soc. Petrol. Engr., Petrol. Expl. Soc. of NY.

SEAL, Warren L. (1): V. Pres. Division Manager, Florida Exploration Co., New Orleans, LA 1978-. Exchange Oil & Gas Corp., Ch. Geol. 1972-78. Amoco Prod. Co., Ch. Geol. (New Orleans and Houston) 1967-72. Mem. Am. Assn. Petrol. Geol., New Orleans Geol. Soc.

STODDARD, Warren G. (7): Dist. Geol., Atlantic Richfield Co., Lafayette, LA 1967-. Richfield Oil Co., Dist. Geol. (New Orleans) 1962-66, Geol. (Bakersfield, CA) 1951-62. Mem. Am. Assoc. Petrol. Geol., Lafayette Geol. Soc., SW LA Geophysical Soc.

YEAGER, John C. (1): Dist. Expl. Geol., S.E. LA Dist., Union Oil of CA, Lafayette, LA 1969-; Area Geol., Middle East, Int. Div. 1966-69; Geol., Tulsa Dist. 1962-66; Geol., Midland Dist. 1960-62. Mem. Am. Assn. Petrol. Geol., Lafayette Geol. Soc., New Orleans Geol. Soc.

AREA G

Jeffery V. Morris, Chairman
Bill C. Burkman, Vice Chairman

BURKMAN, Bill C. (3): Gulf Coast Reg. Geol. and Off. Manager, Oil Development Co. of Texas, Houston, TX; Reg. Geol. 1969-. Nat. Gas Pipeline Co. of Am. (Amarillo & Houston), Jr.-Dist. Geol. 1957-69; Independents Geophysical Surveys Corp., Cofounder & Party Ch. 1954-57; Geophysical Serv., Inc., Computer-Relief Party Ch. (TX, WY & ND) 1951-54. Mem. Am. Assn. Petrol. Geol., Soc. Expl. Geophysicists, Houston Geol. Soc., Panhandle Geol. Soc.

HORSTMANN, Lane E. (4): Dist. Expl. Manager, Enserch Expl. (Lone Star Producing), Houston, TX 1974-; Dist. Geol. 1970-74. Lone Star Producing Co., Expl. Geol. (Abilene, TX) 1967-70, Expl. Geol. (Midland, TX) 1951-57. Indep. Cons. Geol. (Midland & Cameron, TX) 1957-67. Mem. Am. Assn. Petrol. Geol., Houston Geol. Soc., Houston Assn. Petrol. Landmen, Registered Prof. Engr. (TX).

MAYSE, Robert H. (3): V. Pres., Energy Resources, Houston Pipe Line Co. (Intratex, Valley Pipe, HNG Fossil Fuels), Houston, TX 1974-; Manager, Hydrocarbon Reserves 1972-74; Manager, Gas Reserves 1970-72; Sr. Reservoir Geol. 1967-70; Reservoir Specialist (Houston) 1962-64. Mem. Am. Assn. Petrol. Geol. (Cert.), Assn. Prof. Geol. Scientists (Cert.), Houston Geol. Soc., Soc. of Petrol. Engr., Am. Inst. Min., Met. & Petrol. Engr.

*MORRIS, Jeffery V. (4): Manager, Res. Geol., Transcontinental Gas Pipeline Corp., Houston, TX; Reg. Geol., Dist. Geol., Sr. Geol., Geol. 1961-. Sun Oil Co., Geol. (Houston) 1959-61. El Paso Nat. Gas Co., Geol. (New

*Pipelines representative.
**Gas Distributors representative.

Orleans) 1956-59. Gulf Oil Corp., Geol. (New Orleans) 1954. Mem. Am. Assn. Petrol. Geol., Houston Geol. Soc. (Pres. 1978-79), Natural Gas Men of Houston.

**SULLIVAN, Richard A. (6): Pres., So. County Gas and Bristol & Warren Gas Co., Hingham, MA 1959-. Boston Transit System, Exec. & Consulting Eng. 1949-58. Detroit Transit System, Gen. Manager 1945-58. City of Detroit, Public Util. Anal. 1942-45. U.S. Engr., Consulting Engr. 1941-42. MA Dept. Public Util., Elec. Engr. 1937-41. Mem. Am. Gas Assn., NE Gas Assn., Harvard Engr. Soc., MA Soc. Prof. Engr., NH Bar Assn.

AREA H

James A. Barlow, Jr., Chairman
C. Keith Fisher, Vice Chairman

BARLOW, James A. Jr. (3): V. Pres., Barlow & Haun, Inc., Casper, WY 1957-. Forest Oil Corp., Geol. 1953-57. Ohio Oil Co., Geol. 1952-53. Mem. Am. Assn. Petrol. Geol., Assn. Prof. Geol. Scientists, Geol. Soc. Am., Rocky Mtn. Assn. Geol., WY Geol. Assn., Independent Petrol. Assn. Mtn. States.

FISHER, C. Keith (2): Reg. Geol., Panhandle Eastern Pipe Line Co., Denver, CO 1977-. U.S. Geological Survey, Geol. (Denver) 1974-77. Indep. Geol. (Denver) 1973-74. American Stratigraphic Co., Gen. Mgr., Vice Pres. (Denver) 1961-73; Manager (Billings & Casper) 1955-61. Canadian Stratigraphic Serv., Ltd., Geol. (Calgary) 1952-55. Panhandle Eastern Pipe Line, Geol. (Liberal, KS) 1949-52. Mem. Am. Assn. Petrol. Geol., Am. Inst. Prof. Geol., Rocky Mtn. Assn. Geol., WY Geol. Assn., MT Geol. Soc.

**GOLDEN, Jerry B. (3): Development Geol., Mountain Fuel Supply Co., Salt Lake City, UT 1968-. Shell Oil Co., Field Asst. (Farmington, NM) 1965-66. Mem. Utah Geol. Assn.

HAWK, David H. (3): V. Pres. Expl., Sundance Oil Co., Denver, CO 1980-. IGC Production Co., V. Pres. & Gen. Mgr. and Intermountain Gas Co. (Boise, ID); Mgr. Expl. & Prod. 1977-80; Nat. Res. Advisor 1973-76. Tenneco Oil Co., Expl. Geol. (Denver) 1972-73. Atlantic Richfield, Expl. Geol. (Dallas, TX & Lafayette, LA) 1970-72. Mem. Am. Assn. Petrol. Geol. (Energy Minerals Div.), ID Assn. Prof. Geol., Geol. Soc. Am., Rocky Mtn. Assn. Geol., Geothermal Resource Council, Am. Gas. Assn.

KIDWAI, Moid (3): Sr. Reservoir Engr., Northern Natural Gas Co., Denver, CO, 1980-; Sr. Reservoir Engr. (Omaha, NB) 1978-80; Reservoir Engr. 1975-77. Metro Subway, Geol. (Washington, DC) 1974-75. Oil & Gas Development Corp., Petrol. Engr. (Pakistan) 1968-72. Mem. Am. Assn. Petrol. Geol., Am. Gas Assn., Soc. Petrol. Engr.

McPEEK, Lawrence A. (1): Cons. Geol., Denver, CO 1971-. Koch Expl. Co., Expl. Mgr., Rocky Mtn. Reg. (Denver) 1968-71. Amoco Prod. Co., Expl. Geol. (Denver and New Orleans) 1961-68. Mem. Am. Assn. Petrol. Geol., Rocky Mtn. Assn. Geol., WY Geol. Assn.

MOTSCH, A. Sherrill (1): Dist. Devel. Geol., Marathon Oil Co. (formerly The Ohio Oil Co.), Casper, WY 1979-; Devel. Geol. 1967-79; on staff of Div. Geol. & Div. Expl. Mgr. 1957-66; Field & Devel. Geol. (Cody, WY) 1953-57; Field Geol. (Rawlins, WY) 1951-53. Mem. WY Geol. Assn.

MURRAY, D. Keith (7): Expl. Proj. Mgr., Expl. & Min. Div., Colorado School of Mines Research Institute, Golden, CO 1979-. CO Geol. Surv., Denver, CO 1973-79. Coronado Oil Co., Consulting Geol. (Denver) 1969-73. Sinclair Oil Corp. (Denver) 1966-69. Consulting Geol. (Denver) 1962-66. Clark Oil & Refining Corp. (Denver) 1960-62. Indep. Geol. (Los Angeles) 1959-60. Manabi Expl. Co. (Ecuador, SA) 1956-58. Shell Oil Co. (CA, UT, NV, LA) 1953-56. Mem. Am. Assn. Petrol. Geol. (Program Councillor, Energy Minerals Div., Natl. AAPG V. Pres. 1979-80), Am. Inst. Prof. Geol., CO Sci. Soc., Denver Coal Club, Geol. Soc. Am., Rocky Mtn. Assn. Geol., Rocky Mtn. Coal Min. Inst., WY Geol. Assn.

OTT, Henry L. (2): Rocky Mtn. Div. Geol., Chevron U.S.A. Inc., Denver, CO 1975-; Geol. (Denver) 1972-74. Western Australia Petrol. Proprietary Ltd. (Perth), Reg. Strat. Paleon. 1967-71. Mem. Am. Assn. Petrol. Geol., Rocky Mtn. Assn. Geol., WY Geol. Assn.

POWERS, Richard B. (2): Geol., U.S. Geological Survey, Oil & Gas, Lakewood, CO 1974-. Consultant (Denver) 1971-74. Bolyard & Assoc., V. Pres. (Denver) 1968-71. Tenneco Oil, Sr. Staff Geol. (Houston) 1967-68; Dist. Geol. (Casper) 1965-67; Dist. Mgr. (Pittsburgh) 1962-65; Reg. Geol. (Casper & Denver) 1959-62. Petrobras, Geol. (Belem, Brazil) 1958-59. Pure (Union) Oil Co., Geol. (Grand Junction, CO) 1952-58. Mem. Am. Assn. Petrol. Geol. (Membership Committee), Rocky Mtn. Assn. Geol., WY Geol. Assn., Canadian Soc. Petrol. Geol.

SANBORN, Albert F. (2): Consulting Geol., Denver, CO 1978-. Chevron U.S.A., Sr. Geol. (Denver) 1963-78; Div. Stratigrapher (Salt Lake City) 1959-63; District Stratigrapher 1955-59; Geol.-Stratigrapher 1954-55; Geol.-Stratigrapher (Los Angeles) 1952-54. Mem. Am. Assn. Petrol. Geol., Assn. Ind. Petrol. Geol., Rocky Mtn. Assn. Geol.

*STRACKE, Kenneth J. (3): Director, Northwest Pipeline Corp., Salt Lake City, UT 1975-. Consultant (Salinas, CA) 1974-75. Union Oil Co. of CA, Dist. Mgr. (Santa Rosa, CA) 1972-74; Dist. Oper. Mgr. (Orcutt, CA) 1969-72; Dist. Prod. Supt. 1968-69; Dist. Engr. 1968; Engr. Supv. (Coalinga, CA) 1962-68; Petrol. Engr. (San Joaquin Valley, CA) 1954-62. Mem. Am. Gas Assn. (Expl. & Prod. Comm.), Reg. Prof. Engr. UT, Soc. Petrol. Engr. of Am. Inst. Min., Met. & Petrol. Engr. (Chmn. San Joaquin Valley, CA Sec. 1962).

WOSICK, Fred D. (2): Geol., Montana-Dakota Utilities Co., Bismarck, ND 1977-. Mem. ND Academy of Science, ND Geol. Soc., MT Geol. Soc., WY Geol. Assn.

AREA I

Robert D. Habbit, Chairman

ALLSHOUSE, Edward M. (2): Sr. Reservoir Geol., El Paso Natural Gas Co., El Paso, TX 1973-. Mem. Am. Assn. Petrol. Geol., Am. Inst. Min., Met. & Petrol. Engr., El Paso Geol. Soc.

*Pipelines representative.
**Gas Distributors representative.

DAVIES, David J. (2): Geol., Expl. and Dev., Southern Union Exploration Co. (SX); Dallas, TX 1977-. Enserch Exploration, Inc. (Lone Star Producing Co.), Geol. (Dallas) 1975-77. Mem. Am. Assn. Petrol. Geol., Soc. Econ. Paleon. and Min., Dallas Geol. Soc.

**GASS, Bernard (2): Manager, Fuel Supply, Arizona Public Service Co., Phoenix, AZ.

HABBIT, Robert D. (4): Mgr. Reservoir Engineering, El Paso Natural Gas Co., El Paso, TX 1978-; Mgr. Reservoir Studies 1978; Consulting Reservoir Geol. 1977-78; Staff Geol. 1966-77. Indep. Geol. (Houston) 1965-66. El Paso Natural Gas Co., Sr. Reservoir Geol. (Houston) 1957-65. Sohio Petroleum Co., Geophysicist Geol. (Gulf Coast-Rky. Mtn.) 1954-57. Mem. Am. Assn. Petrol. Geol. (CPG #166), Am. Inst. Prof. Geol. (Cert. #2489), Am. Inst. Min., Met. & Petrol. Engr., Soc.,Expl. Geophysicists, Rocky Mtn. Assn. Geol., El Paso Geol. Soc.

KOTTLOWSKI, Frank E. (2): Dir. & Sr. Geol., NM Bureau of Mines & Mineral Resources, Socorro, NM 1974-; Assoc. Dir., Sr. Geol., Econ. Geol. 1951-74. Indiana Geol. Surv., Party Chief, Coal Div. 1947-51. Indiana Univ. Geol. Dept., Inst. 1950-51. Mem. Am. Assn. Petrol. Geol. (Editor 1971-75), Geol. Soc. Am. (Fellow), Soc. Econ. Geol., Assn. Am. State Geol., Soc. Econ. Paleon. & Min., Assn. Prof. Geol. Scientists (Past Pres. NM section), Am. Assn. Adv. Science (Fellow).

KRIVANEK, Connie M. (2): Sr. Geol., Mountain Fuel Supply Co., Farmington, NM 1976-. Union Oil Co. of CA, Geol. (Midland, TX) 1976; (Durango, CO) 1967-76; (Olney, IL) 1967. Superior Oil Co., Geol. (New Orleans) 1965-67; (Bakersfield, CA) 1964-65; (Anchorage, AK) 1963-64; (Casper, WY) 1963. Mem. Am. Assn. Petrol. Geol., Rocky Mtn. Assn. Geol., Four Corners Geol. Soc., Am. Inst. Prof. Geol. (Cert. #2820).

*VAUGHAN, W.L. (3): Gen. Mgr. Reserves Evaluation Dept., Texas Eastern and Transwestern Pipelines, Houston, TX 1973-. Texas Eastern Trans. Corp., Asst. Mgr., Reserves and Deliverability 1972-73, Jr. Petrol. Engr.-Engr. (Gas Supply Dept.) 1957-72. Mem. Am. Gas Assn. (Chmn., Underground Gas Storage Comm.), Soc. Petrol. Engr., Nat. Gas Men Permian Basin.

AREA J-N

Alan F. Chatfield, Chairman
Joe E. McGarrah, Vice Chairman

CHATFIELD, Alan F. (3): Chief Geol., Berry Petroleum Corp., Oklahoma City, OK 1980-. French Oil Co., Expl. Mgr. 1980. GHK Corp., Expl. Mgr. 1976-80. Carlsberg Petrol. Corp., Sr. Staff Explorationist (CA) 1974-76. Oceanic Expl. Co., Geophysicist & Local Overseas Mgr. 1973-74. Continental Oil Co., Geophysicist 1972-73. GHK Corp., Geophysicist 1971. Humble Oil & Refining Co., Geophysicist (TX & OK) 1967-71.

CURRY, James K. (8): Mgr., Rocky Mtn. Region Panhandle Eastern Pipe Line Co., Denver, CO 1975-; Mgr. Expl. & Prod. (Pan Eastern Expl., Houston) 1973-75; Mgr. Expl., Mgr. Geol., Dist. Geol., Geol., Jr. Geol. (Liberal, KS) 1946-72. Mem. Am Assn. Petrol. Geol., Soc. Petrol. Engr., Rocky Mtn. Assn. Geol., Rocky Mtn. Nat. Gas Men's Assn., Assn. Prof. Geol. Scientists (Cert. #4353).

**McGARRAH, Joe E. (3): Sr. Geol., Oklahoma Nat. Gas Co., Tulsa, OK 1973-, National Assn. Petrol. Co., Regional Geol. (Tulsa) 1956-73. Frost Geophysical Co., Geophysicist Training (Tulsa) 1954-56. U.S. Air Force Intelligence Div., Photo Interpreter 1952-53. U.S. Geol. Surv., Topographic Engr. (Rolla, MO) 1951-52. Mem. Am. Assn. Petrol. Geol., Tulsa Geol. Soc., OK City Geol. Soc., Rocky Mtn. Assn. Petrol. Geol., OK Gas Men's Assn.

*WADE, Philip J. (2): Mgr. Anadarko Supply Evaluation, Northern Natural Gas Co., Tulsa, OK 1978-; Dir. Supply Operation (Midland, TX) 1976-78; Production Engr. 1976. Hilliard Lyons (Bowling Green, KY) 1975-76. Cities Service Oil Co., Petrol. Engr. (Oklahoma City) 1972-74; Prod. Engr. (Liberal, KS) 1971-72. Mem. Soc. Petrol. Engr., Nat. Gas Men of Permian Basin, Am. Gas Assn. (Mid-Continent Reserve Comm.).

AREA J-S

Charles M. Allen, Chairman
James F. Fleming, Vice Chairman

ALLEN, C. M. (8): Consultant, Expl. & Prod. Affairs Industry & Govt., No. Am. Expl. & Prod. Div., Phillips Petrol. Co., Bartlesville, OK 1944-. Adv. Board to Dept. of Geol., Univ. KS 1973-. Mem. Am. Assn. Petrol. Geol. (Comm. on Statistics of Drlg.), Nat. Petrol. Council (Comm. on Emergency Preparedness 1974-76, Comm. on U.S. Energy Outlook 1970-73), Fed. Power Comm. Natl. Gas Surv. (Gas Supply Task Force 1971-75). Has testified in numerous state conservation agency, state and federal courts, and Fed. Power Comm. proceedings (including all major area and national rate proceedings), and hearings before Senate and House Congressional Committees.

*CURRY, James K. (8): Mgr., Rocky Mtn. Region Panhandle Eastern Pipe Line Co., Denver, CO 1975-; Mgr. Expl. & Prod. (Pan Eastern Expl., Houston) 1973-75; Mgr. Expl., Mgr. Geol., Dist. Geol., Geol., Jr. Geol. (Liberal, KS) 1946-72. Mem. Am Assn. Petrol. Geol., Soc. Petrol. Engr., Rocky Mtn. Assn. Geol., Rocky Mtn. Nat. Gas Men's Assn., Assn. Prof. Geol. Scientists (Cert. #4353).

**FLEMING, James F. (2): Staff Reservoir Engr., Northern Natural Gas Co., Midland, TX 1973-. Exxon, Engr. 1954-73. Mem. Soc. Petrol. Engr., Am. Gas Assn. (Rocky Mountain subcommittee).

AREA K

Alexander Sisson, Chairman

CARPENTER, JoAnn (1) (alternate for James E. Schroeder): Pacific Alaska LNG Associates, Anchorage, AK.

*Pipelines representative.
**Gas Distributors representative.

HARRISON, Charles R. (3): Mgr. Alaska Opr., Texas Eastern Exploration Co., Houston, TX 1974-; Union Oil Co. of CA, Geol. (New Orleans, Midland, Roswell, Anchorage) 1956-74. Mem. Am. Assn. Petrol. Geol., Soc. Petrol. Engr.-AIME, AK Geol. Soc., Geophysical Soc. AK, AK Assn. Petrol. Landmen.

HARTMAN, Donald C. (4): Geologist, Landman, Texaco Inc., Anchorage, AK 1975-; AK State Geol. 1973-74; AK Petrol. Geol. 1971-73, Texaco Inc., Geol. (Los Angeles and Anchorage) 1956-71. Mem. Am. Assn. Petrol. Geol., AK Geol. Soc., AK Assn. Petrol. Landmen.

HITE, David M. (1): District Geol., ARCO Oil & Gas Co., Anchorage, AK 1979-; Sr. Staff Geol. (Dallas) 197?-79; Sr. Geol. (Anchorage) 1975-77; Sr. Research Geol. (Dallas) 1970-74; Research Geol. 1967-70. Mem. AK Geol. Soc.

LIAN, Ernest B. (4): Sr. Geol., Marathon Oil Co., Anchorage, AK 1965-; Dist. Geol. (Bakersfield) 1963-65; Geol. & Dist. Geol. (Los Angeles) 1950-63. Mem. Am. Assn. Petrol. Geol., AK Geol. Soc., Geophysical Soc. AK.

McKEEVER, John H. (1): Staff Geol., Amoco Production Co., Anchorage, AK 1966-; Geol. (Western Canada and Northern Rocky Mountains) 1948-66, California Standard Co., Geol. (Canada) 1947-48. Mem. AK Assn. Petrol. Landmen, AK Geol. Soc., Am. Assn. Petrol. Geol., Geol. Soc. Am. (Fellow), Geophy. Soc. AK, Soc. Expl. Geophy.

McMULLIN, Robert H. (1): Geol., Branch of Oil & Gas Resources, U.S. Geol. Survey, Anchorage, AK 1979-; Area Geol. 1976-79; OCS Evaluation Supervisor 1975-76; Geophysicist, Conservation Div. 1971-75, Chevron U.S.A. Inc., Expl. Geol. & Geophysicist (CA, WA, OR, NV, AK) 1955-71. Mem. AK Geol. Soc., Am. Assn. Petrol. Geol., Geophy. Soc. AK, Soc. Econ. Geol.

*SCHMIDT, Harold F. (4): Sr. V. Pres., Alaska Pipeline Co., Alaska Gas & Service Co., Anchorage, AK 1978-; V. Pres. 1962-78, Public Serv. Co. of CO, Gas Utilization Engr. (Denver) 1955-62, Southern CA Gas Co., Indust. Serv. Tech. (Los Angeles) 1954-55.

**SCHROEDER, James E. (3): Geol. Supv., Sr. Geol., Planning Geol., Southern California Gas Company, Los Angeles, CA 1973-, Standard Oil Co. of CA, Expl. Geol. (La Habra & San Francisco) 1967-73. Mem. Am. Assn. Petrol. Geol., Soc. Expl. Geophysicists, AK Geol. Soc., Rocky Mtn. Coal Inst.

SISSON, Alexander (4): Sr. Geol., Union Oil Co. of California, Anchorage, AK 1966-, Esso Standard Oil, Sr. Geol. (Bogota) 1964-66; Geol. (Guatemala) 1961-63; Geol. (Havana) 1957-60, Carter Oil Co., Geol. (Denver) 1951-56. Mem. Am. Assn. Petrol. Geol. (Environmental Comm.), AK Geol. Soc. (Pres. 1977).

*Pipelines representative.
**Gas Distributors representative.

AREA L

William F. Edmondson, Chairman
Wesley E. Franklin, Vice Chairman

CASS, John T. (1): Div. Geol., Rocky Mtns., Four Corners area, Western U.S., Alaska, offshore, Texaco Inc., Los Angeles, CA 1955-, U.S. Geol. Survey, Alaska, 1951-55. Mem. Am. Assn. Petrol. Geol.

EDMONDSON, William F. (7): Consultant, Bakersfield, CA 1980-, Mariposa Petroleum Co., V. Pres. (Bakersfield) 1976-80, Westates Petroleum Co., Geol. 1975, Consultant (Sacramento Valley) 1959-74, Superior Oil Co., Geol. 1957-59, 1952-54. Mem. Am. Assn. Petrol. Geol., San Joaquin Geol. Soc.

FRANKLIN, Wesley E. (1): Division Geol., Tenneco Oil Co., Bakersfield, CA 1978-; Geol. 1973-78, Gulf Oil Co., Prod. Geol. (Morgan City, LA) 1969-71. Mem. Geol. Soc. Am., Am. Assn. Petrol. Geol. (Pacific Sec.), San Joaquin Geol. Soc., Soc. Econ. Geophys., Soc. Econ. Paleon. & Min.

GARSIDE, Larry J. (3): Energy Resources Geol., Nevada Bureau of Mines and Geology, Mackay School of Mines, Univ. of Nevada, Reno, NV 1968-; Research Asst. 1965-67, Nevada Oil and Gas Conservation Commission, Executive Secretary 1974-75. Mem. Am. Assn. Petrol. Geol. (Mem. Energy Resources Div.), Geol. Soc. Am. (Fellow), Geol. Soc. NV (Sec.-Treas. 1969-70; Pres. 1973-74), Geothermal Resources Council, Soc. Econ. Geol.

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*LUDWICK, L. E. (6): Manager, Reservoir Geology, Reservoir Engineering Dept., El Paso Natural Gas Co., Houston and El Paso, TX 1954-, Standard Oil Co. of TX, Development Geol. 1950-54, Caran Bros. Engr. Co., Well Logging Engr. 1950. Mem. Am. Assn. Petrol. Geol., Soc. Petrol. Engr., Am. Gas Assn. (Natural Gas Reserves Comm.), El Paso Geol. Soc.

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Plate 1
POTENTIAL GAS COMMITTEE

NATURAL GAS MAP OF THE UNITED STATES

December 31, 1980

AREAS OF GAS PRODUCTION INCLUDING GAS ASSOCIATED WITH OIL

AREAS IN WHICH SEDIMENTARY ROCKS ARE EXPOSED AT THE SURFACE OR ARE PRESENT AT DEPTH AND COVERED AT THE SURFACE BY EXTRUSIVE IGNEOUS ROCKS

AREAS IN WHICH INTRUSIVE IGNEOUS ROCKS OR METAMORPHIC ROCKS ARE EXPOSED AT THE SURFACE

LIMITS OF SEDIMENTARY BASINS AS RECOGNIZED BY THE POTENTIAL GAS COMMITTEE. DASHED WHERE INFERRED

CONTOUR LINE INDICATING THICKNESS OF SEDIMENTS

1980 ESTIMATED POTENTIAL SUPPLY OF NATURAL GAS
(Trillions of Cubic Feet)

AREA	PROBABLE	POSSIBLE	SPECULATIVE
A	26	9	51
B	6	7	41
C	<0.5	2	1
D	9	22	20
E	25	56	<0.5
G	30	35	4
H	40	78	69
I	2	3	1
J-NORTH	27	66	42
J-SOUTH	16	34	1
K-ALASKA	8	29	108
L	1	17	24
TOTAL UNITED STATES	193	358	362

Western Thrust Belt

The Western Thrust Belt especially the central portion which is located along the Wyoming-Idaho border, has become a major target for exploration. Significant gas fields have been discovered in southwestern Wyoming and northern Utah. While the eastern boundary of this belt is fairly well defined by the limits of thrust faults, the western boundary is much more nebulous. Some interpretations extend the Western Thrust Belt southeastward from southern Nevada through Arizona, southwestern New Mexico, westernmost Texas and into Mexico. At the present time, the only areas within the Thrust Belt in which estimates of potential resources of natural gas have been made are the northern, central, and southern portions indicated on the map. Because of lack of positive confirmation of the extention of the Thrust Belt south of Utah and the lack of data on potential source rocks, reservoir rocks and trapping mechanisms, no estimate of any potential resource of natural gas has been made for this area.

Eastern Overthrust Belt

Recent exploratory activity and geophysical data have led to the interpretation of an Eastern Overthrust Belt extending from Canada southward into Georgia and Alabama. In the western portion of this belt, sedimentary rocks are exposed at the surface. In the eastern portion, sedimentary rocks are believed to exist beneath metamorphic rocks. Preliminary estimates of natural gas potential for the Eastern Overthrust Belt are included in the estimates reported for Area A.

Exposed Sediments

Concealed Sediments

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Plate 2

POTENTIAL GAS COMMITTEE

NATURAL GAS MAP OF ALASKA

December 31, 1980

1980 ESTIMATED POTENTIAL SUPPLY OF NATURAL GAS IN ALASKA
(Trillions of Cubic Feet)

PROBABLE - 8 POSSIBLE - 29 SPECULATIVE - 108

AREAS OF GAS PRODUCTION INCLUDING GAS ASSOCIATED WITH OIL

AREAS IN WHICH SEDIMENTARY ROCKS ARE EXPOSED AT THE SURFACE OR ARE PRESENT AT DEPTH AND COVERED AT THE SURFACE BY EXTRUSIVE IGNEOUS ROCKS

AREAS IN WHICH INTRUSIVE IGNEOUS ROCKS OR METAMORPHIC ROCKS ARE EXPOSED AT THE SURFACE

LIMITS OF SEDIMENTARY BASINS AS RECOGNIZED BY THE POTENTIAL GAS COMMITTEE. DASHED WHERE INFERRED

SEDIMENTARY BASINS BELIEVED NOT TO HAVE POTENTIAL FOR NATURAL GAS

CONTOUR LINE INDICATING THICKNESS OF SEDIMENTS

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